Reports File
Post
Ed

GEORGIA INSTITUTE OF TECHNOLOGY
OFFICE OF RESEARCH ADMINISTRATION

RESEARCH PROJECT INITIATION

Date: September 25, 1974

Project Title: Estimation of Model Parameters for Power System Monitoring and Control

Project No: E-21-645

Principal Investigator Dr. A. S. Debs

Sponsor: National Science Foundation

Agreement Period: From 10/1/74 Until 9/30/76

Type Agreement: Grant No. ENG74-17527

Amount: $21,000 NSF
3,403 GIT (E-21-328)
$24,403 Total

Reports Required:
Final Summary Report

Sponsor Contact Person (s):

Technical Matters
Dr. M. S. Ghausi, Section Head
Electrical Sciences & Analysis Section
National Science Foundation
Washington, D. C. 20550

Administrative Matters
thru ORA
Mr. F. G. Naughten
Grants Manager
National Science Foundation
Washington, D. C. 20550

Assigned to: Electrical Engineering

COPIES TO:

Principal Investigator
School Director
Dean of the College
Director, Research Administration
Director, Financial Affairs (2)
Security-Reports-Property Office
Patent Coordinator

Library
Rich Electronic Computer Center
Photographic Laboratory
Project File
Other

RA-3 (6-71)

GEORGIA INSTITUTE OF TECHNOLOGY
OFFICE OF CONTRACT ADMINISTRATION

Posted
OCA

SPONSORED PROJECT TERMINATION

Date: April 28, 1977

Project Title: Estimation of Model Parameters for Power System Monitoring and Control

Project No: E-21-645

Project Director: Dr. A. S. Debs

Sponsor: National Science Foundation

Effective Termination Date: 9/30/76

Clearance of Accounting Charges: 9/30/76

Grant/Contract Closeout Actions Remaining: none

- _ Final Invoice and Closing Documents
- _ Final Fiscal Report
- _ Final Report of Inventions
- _ Govt. Property Inventory & Related Certificate
- _ Classified Material Certificate
- _ Other ____________

Assigned to: EE (School/Laboratory)

COPIES TO:

Project Director
Division Chief (EES)
School/Laboratory Director
Dean/Director—EES
Accounting Office
Procurement Office
Security Coordinator (OCA) ✓
Reports Coordinator (OCA)
Library, Technical Reports Section
Office of Computing Services
Director, Physical Plant
EES Information Office
Project File (OCA)
Project Code (GTRI)
Other ____________

CA-4 (3/76)

Washington, D.C. 20550

RESEARCH GRANT BUDGET & FISCAL REPORT

Form Approved
Budget Bureau No. 99-R0013

Please read instructions on reverse side carefully before completing this form.

INSTITUTION AND ADDRESS	NSF PROGRAM	GRANT PERIOD
Georgia Institute of Technology, Atlanta, Georgia	System Theory and Applications	from 10/1/74 to 9/30/76; REPORTING PERIOD from 10/1/74 to 12/30/76 (a)
GRANT NUMBER: NG74-17527; BUDGET DUR. (MOS.): 18	PRINCIPAL INVESTIGATOR(S): Debs	GRANTEE ACCOUNT NUMBER: E-21-645

	NSF Funded Man Months: Cal.	Acad.	Summ.	NSF AWARD BUDGET	CUMULATIVE GRANT EXPENDITURES *Do Not Round*
A. SALARIES AND WAGES					
1. Senior Personnel					
a. 1 (Co)Principal Investigator(s)		3	2	$ 9,583	
b. Faculty Associates					
Sub-Total				$ 9,583	$ 10,246.49(b)
2. Other Personnel (Non-Faculty)					
a. Research Associates—Postdoctoral					
b. Non-Faculty Professionals					
c. 1 Graduate Students				1,000	
d. Pre-Baccalaureate Students					
e. Secretarial—Clerical					
f. Technical, Shop, and Other					
TOTAL SALARIES AND WAGES				$ 10,583	$ 10,346.49
B. STAFF BENEFITS IF CHARGED AS DIRECT COST				815	725.41
C. TOTAL SALARIES, WAGES, AND STAFF BENEFITS (A + B)				$ 11,398	$ 11,071.90
D. PERMANENT EQUIPMENT (Cabinet for Computer Programs)				300	-0-
E. EXPENDABLE EQUIPMENT AND SUPPLIES					65.04
F. TRAVEL 1. DOMESTIC (INCLUDING CANADA)				400	411.97
2. FOREIGN					-0-
G. PUBLICATION COSTS				323	332.25
H. COMPUTER COSTS IF CHARGED AS DIRECT COST				400	606.49
I. OTHER DIRECT COSTS: Relocation Costs				1,300	1,278.65
J. TOTAL DIRECT COSTS (C through I)				$ 14,121	$ 13,766.30
K. INDIRECT COSTS: 65% of Salaries and Wages				6,879	7,035.61(c)
L. TOTAL COSTS (J plus K)				$ 21,000	$ 20,801.91
M. AMOUNT OF THIS AWARD (ROUNDED)				$ 21,000	
N. CUMULATIVE GRANT AMOUNT				$	
O. UNEXPENDED BALANCE (N. BUDGET MINUS L. EXPENDITURE)					$ 198.09

REMARKS: Use extra sheet if necessary
(a) No obligations were made outside the grant period of 10/1/74 through 9/30/76.
(b) Does not exceed five months salary.
(c) 68% of $10,246.49 = $7,035.61.

FOR NSF USE ONLY
Final Fiscal Report Accepted
Grant Closed ______ Remains Open ______
By ______ Date ______
Grants Administration Section, Area ______

SIGNATURE OF PRINCIPAL INVESTIGATOR	TYPED OR PRINTED NAME	DATE
A. S. Debs	A. S. Debs	Jan 5, 1977

I CERTIFY THAT ALL EXPENDITURES REPORTED ARE FOR APPROPRIATE PURPOSES AND IN ACCORDANCE WITH THE AGREEMENTS SET FORTH IN THE APPLICATION AND AWARD DOCUMENTS

SIGNATURE OF AUTHORIZED OFFICIAL	TYPED OR PRINTED NAME & TITLE	DATE
C. Evan Crosby	C. Evan Crosby, Associate Director of Financial Affairs	1/7/77

FOR NSF USE ONLY

Org. Code	F.Y.	Fund ID	Prog. Code	Ob. Class	O/Dres.	Award No.	Amd.	Inst. Code	Unexpended Balance	Trans.	Lot
									$		

NSF Form 98, JULY 1971 — *SUPERSEDES ALL PREVIOUS EDITIONS*

SECURITY ASSESSMENT OF POWER SYSTEMS

A. S. Debs
Georgia Institute of Technology
Atlanta, Georgia

A. R. Benson
Bonneville Power Administration
Portland, Oregon

ABSTRACT

A review of the state of the art in assessing the security of power system operations is provided. Emphasis is placed on the overall philosophy of preventive system operation, and the computational and data acquisition systems required for on-line monitoring and analysis of system security. Critical comparison of various approaches is provided. Recommendations for effective security assessment for a single company, as well as, an interconnection are provided. Furthermore, industry practices and guidelines in the area of system security are presented and commented upon.

1. INTRODUCTION

1.1 Definition of System Security

A secure operating state of a power system is defined as that state which is invaluable to unacceptable system conditions such as:

- cascading outages;
- system separation;
- wide-spread outages (blackouts);
- violation of emergency limits of line current;
- bus voltages, or system frequency; and
- loss of synchronization among generators.

Simply stated, the process of security assessment consists of judging if the system is in a secure operating state. No power system, however, is secure in the above sense. Catastrophic disturbances, simultaneous critical faults, or other improbable but possible occurrences can bring any utility system into any or all of these unacceptable system conditions. Economics and the realities of physical construction dictate that some attainable measure of security be supplied. This measure is usually in terms of the invulnerability of the system to single faults, single occurrences of loss of generation, or other credible contingencies.

It should be noted immediately that it is the security of the bulk power transmission that is being considered. Customer service interruptions at the distribution level are not included although they may occur if the bulk power transmission system fails.

1.2 Historical Background

Historically, the system planner always has considered the security of the system by providing comfortable margins of generating capacities, transmission line capabilities and tie-line interconnections. The planner, however, could not predict all possible system configurations and system demands. A system which is well planned under adequate engineering assumptions for secure operation will not be so necessarily under unpredicted conditions. The 1965 Northeast blackout and similar events[238] showed clearly that a well-planned system is indeed vulnerable to possible disturbances and that this vulnerability can be catastrophic. Not only the planner but now the system operator is very much concerned about security and its assessment.

The first analysis of the problem of security was by Stienmetz[1] who studied the effect of disturbances on systems' stability. In 1926, Evans and Wagner[2] proposed some stability-enhancing schemes like the use of a ground-current relay to decrease prime-mover input by governor control. And in 1930, Summers and McClure[3] proposed using a dynamic braking resistor for stability augmentation. Many works on related topics appeared since then. However, it was around 1968 when DyLiacco[16] formulated the new philosophy of secure operation. In essence, he decomposed system operation into three states: Normal; Emergency; and Restorative. In the Normal State all system equality and inequality constraints are satisfied. In the Emergency State some of the inequality constraints are violated (e.g., frequency drops, overloading of lines, etc.). Finally, in the Restorative State some of the equality constraints are not satisfied. (e.g., a load area is not serviced but the rest of the system is in the Normal State.) Refinements of these definitions were later obtained whereby the Normal State was decomposed into two states: Secure and Alert (or Insecure). A Secure Normal State is a Normal State whereby single system contingencies will not cause any transitions from the Normal State. In the Alert (or Insecure) Normal State a single system contingency can cause a transition to an Emergency State. A representative diagram of state transitions is shown in Figure 1.

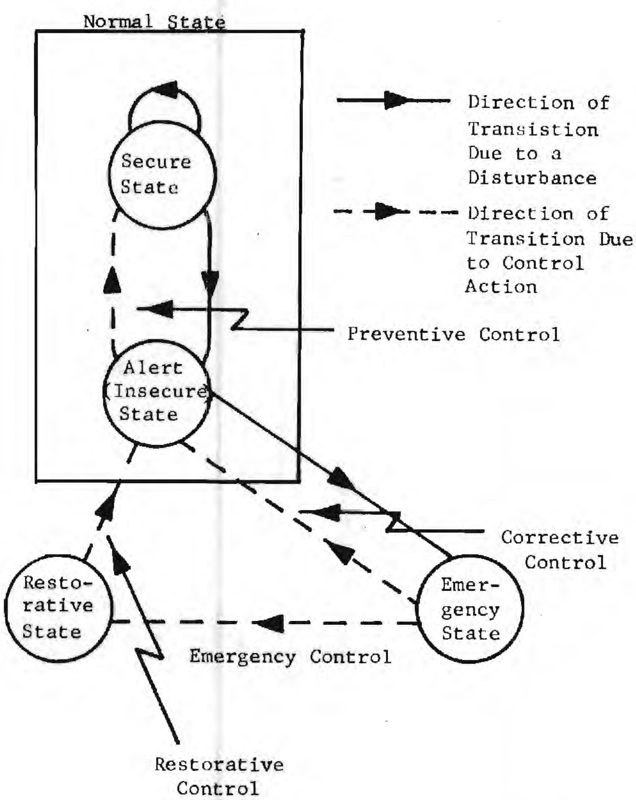


Figure 1. Schematic Diagram of System Operating States and Associated State Transitions Due to Disturbances and Control Action

1.3 Applications of Security Assessment Methods

Analysis of system security is a primary function in three major applications: long term planning; planning of operations; and minute-by-minute operation. Specific applications are listed as follows:

1. Long-Term Planning
   - evaluation of generation capacity requirements
   - evaluation of interconnected system power exchange capabilities
   - evaluation of transmission system adequacy.
2. Planning of Operations
   - determination of spinning reserve requirements in the unit committment process
   - scheduling of hourly generation as well as interchange scheduling among neighboring systems
   - outage dispatching of transmission lines and transformers for maintenance and system operation.
3. On-Line Operation
   - monitoring of the operating state of the system
   - contingency evaluation
   - prediction of the level or measure of system security in the near term
   - providing inputs to security enhancement functions.

The primary concern of this report is on on-line operation since this is the area where most significant recent progress has taken place. The impact of this on long-term and operational planning, will however, be discussed.

1.4 General Problem Framework

Security assessment is part of an overall operating strategy to maintain the system in the Normal State as long as possible. Inputs to the security assessment process consist of:

- on-line telemetry data provided periodically every few seconds
- mathematical models of the system
- information on external interconnected systems
- system operating limits
- types and locations of possible disturbances
- security enhancement control strategies
- historical data
- uncertainties associated with measurements, mathematical models and predictions defined by means of probability distributions.

The outputs of the process provide a measure of system security. Definition of such a measure is, at present, controversial and dependent on certain philosophies to be elaborated upon later. These outputs, at any rate, are the basis of security enhancement strategies.[343] A strong and mutual coupling exists between security assessment and security enhancement. Violation of a security limit requires preventive control action. However, the availability of an adequate corrective strategy means that the system is inherently more secure. All of this is done with strong regard of operator evaluation and action, and consequently, the design of effective on-line interactive systems.

The security assessment process itself consists of two primary functions:*

1. Security Monitoring: this consists of the processing of incoming data, correlating it with available data in order to reliably determine the operating state of the system at present or in the near future.
2. Security Analysis: this consists of simulating the system under various contingency conditions in order to evaluate the measure of system security and provide inputs to enhancement strategies.

In either of the above functions updated mathematical models of the system are required. These models are classified as steady-state (static) and dynamic. And each class can be deterministic or stochastic. Furthermore, all modeling assumptions, whether in the static or dynamic cases, are of varying degress of complexity depending on:

- computational requirements;
- on-line data requirements;
- data on model paramters;
- model reliability; and
- required solution accuracies.

System disturbances are classifed into load and event disturbances. Load disturbances consist of small random fluctuations superimposed on slowly varying trend changes. Both the slow trends and the statistics of the small random disturbances can be predicted by forecasting methods (if the data is available). Event disturbances consist of:

- faults on transmission lines;
- cascading events due to protective relay action following severe overloads or violation of operating limits;
- generator outages due to loss of synchronism or malfunctions;
- sudden and large load changes.

Transmission line outages are generally due to weather (lightning or storms), improper relaying, operator errors or accidents (falling trees, airplanes, contact by construction equipment, etc.). Most such outages will affect single lines. However, multiple line outages may occur due to bus faults or accidents involving multiple line towers. Therefore they should not be disregarded entirely. Statistics on transmission line outages may or may not be available in a given utility. In general, however, higher voltage lines have smaller outage rates. Generator outage statistics are perhaps more understood with data available on most systems. In general, generator outages are more frequent with new units.

In Table I a summary is provided for the possible impact of various disturbance types on system security. It is clear from that table that maintaining the system in the Secure Normal State should be a highly desirable objective provided that the cost of so doing is not prohibitive.

1.5 Summary of Present Status

Present and projected efforts in the security assessment field consist, to our knowledge, in activites in the following areas:

*The decomposition here is not unique since some utilities would use "Security Monitoring" to mean both of these primary functions. However, we are adopting these definitions to be consistent with DyLiacco.[63]

TABLE I. Effect of Various Types of Disturbances on System Security

#	DISTURBANCE TYPE	POSSIBLE OUTCOMES	IMPACT ON SECURITY
1	Faulted line which is cleared (3-phase and otherwise)	(a) Stable system (b) Loss of synchronism leading to generator tripping	(a) Secure Normal State (b) Generation-Load imbalance which may lead to an emergency if spinning reserves are not sufficient or to long-term dynamic instability.
2	Permanent Line fault leading to line outage	(a) Stable system with acceptable steady-state response (b) Stable system with unacceptable steady-state response	(a) Secure Normal State (b) Steady-State emergency requiring corrective action. Otherwise cascading events will occur.
3	Generator Outage	(a) Stable system with acceptable steady-state response (b) Stable system with unacceptable steady-state response (c) Dynamic instability due to inadequate reserves	(a) Secure Normal State (b) Same as 2(b) (c) Emergency State requiring emergency control

a. Development of several computationally efficient steady-state contingency evaluation programs to test steady-state response to generator or line outages. Each program has its advantages and limitations and is strongly dependent on the type of on-line data base used or proposed.

b. Development of feasible transient and long-term dynamic stability contingency evaluation algorithms which are based on different approaches. Some of these include:

- use of Lyapunov's functions;
- digital computer numerical integration;
- hybrid computer on-line simulation.

c. Off-line computation of security functions by means of pattern recognition methods to be used in on-line operation.

d. Development of security indices based on contingency evaluation to aid the dispatcher to assess system security through interactive displays.

e. Development of probabilistic measures of security which are based on methods of reliability evaluation.

f. Development of optimum power flow programs with security constraints.

The remainder of this paper will discuss these topics from a critical point of view. Following that, a section is devoted to discussions and recommendations.

2. ANALYSIS OF PRESENT STATUS

2.1 Steady-State Security Assessment

In steady-state security assessment use is made of nonlinear power flow network models or, in some cases, linear steady-state current/voltage models. Analysis based on these models is natural since the Normal State is essentially in the steady-state and since most operating limits can be defined in terms of power flow, current and voltage quantities. Furthermore, these models are amenable to on-line computer analysis and are well understood by engineers.

In the discussion below emphasis will be placed on the following topics:

- steady-state security monitoring;
- steady-state contingency evaluation;
- contingency evaluation modeling requirements.

2.1.1 Steady-State Security Monitoring

A. Data Base Systems

In steady-state security monitoring the objective is to determine, on a minute-by-minute basis, whether the system is in the Normal State or not. To do so, on-line data acquisition systems are required to various degrees of complexity. A minimal data acquisition system should provide information on the status of all major transmission and generation elements together with analog data on power flows, generation levels and inter-tie flows. The major transmission elements to be monitored should be determined in off-line studies during the planning phase. Such a minimal system should have the following capabilities:

- Drive operator displays to show major station single line diagrams, key flows on major lines, and generation levels; and
- Provide inputs for approximate contingency evaluation algorithms like the distribution factors algorithm.

An intermediate system will require an on-line ac power flow solution for the main grid network of a given utility. The trend, at present is to do so by means of extensive data acquisition system (Supervisory Control and Data Acquisition--SCADA), which provides status information on all lines, transformers and generators together with redundant measurements of power flows, voltages, loads and generation levels. The statistical techniques of Weighted Least Squares estimation coupled with Bad Data Rejection algorithms proved reliable, and hopefully accurate, on-line power flow solutions. The advantages of this over the minimal system are:

- All power flow outputs, measured or otherwise, are available to the display system. Furthermore, voltage and various quantities provide an added significant input.
- Contingency evaluation can be performed using ac methods provided adequate external network equivalents are available.
- Short-term bus load forecasting is possible. This provides a data base for predictive security analysis operational planning, and possibly, on-line automatic control.[143]

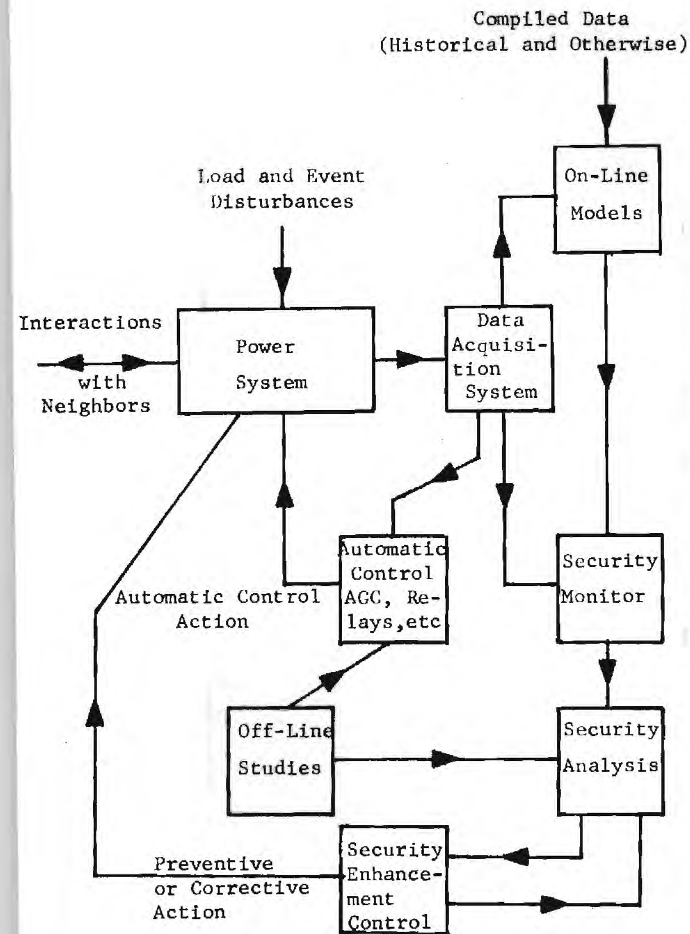


Figure 2. Major Functions Involving Control and Security of System Operation

- Improved economic dispatching through the availability of accurate load values and network configurations. Here an improved B-constant approach or an optimum power flow become possible.

A maximal system would consider the problem of interconnected system security. Here a coordination computer will act as a medium of data processing of vital data of interest to the interconnection as a whole. The individual pool members may have intermediate or minimal systems. The coordination computer will provide the following added advantages:

- Ability to perform contingency analysis (on a company level or a pool-wide level) with accurate knowledge of the status of the entire interconnection.
- Ability to evaluate emergency transfer capabilities on-line.
- Ability to perform pool economic dispatching.
- Improved emergency and security enhancement controls.

At present, most security monitoring systems are of the minimal or intermediate type (see Appendix B). However, some large interconnections perform, at least, the economic dispatching function on the pool level.

B. State Estimation

The role of state estimation is to provide a reliable and accurate estimate of bus voltage magnitudes and phase angles, real and reactive power flows, as well as, real and reactive bus power injections. This is achieved by overmeasuring the system with more measurements than are needed to solve a load flow problem. This redundancy enables a form of cross-checking among measurements to eliminate any gross measurement or system configuration errors. It also makes it possible to obtain power flow and injection estimates which are more accurate, on the average, than meter readings, provided that the network data is itself very accurate.

At present, there are a variety of state estimation programs with various characteristics. They are all based on the so-called static state estimation concept whereby a snapshot scan of the system provides all the information needed for computation. Furthermore, they all attempt to minimize the weighted least square errors between measured and estimated quantities.

In Table II, the following state estimation methods are compared:*

1. Sequential State Estimation (SSE)[87]
2. American Electric Power Method (AEP)[83]
3. AEP'S Method modified to include bus voltages and line currents (Modified AEP)[90]
4. Decoupled Weighted Least Squares (Decoupled WLS)[89]
5. Weighted Least Squares (WLS)[77]
6. Generalized Load Flow (GLF)[88]

In addition to that table, the following comments are made:

(a) All these methods except SSE use sparse matrix techniques;

(b) They are very competitive with one another in terms of computational speed;

(c) An exact comparison among them is difficult to obtain since different methods use different measurement systems;

(d) These comparisons are based on our experience with simulated tests. Our experience with actual system data indicate serious network modeling problems which degrades the accuracy of solutions.[125]

Several approaches to the detection and identification of gross measurement or modeling errors have been reported. However, there is no report on actual operating experience.[115-119]

2.1.2 Steady-State Contingency Evaluation Methods

A. Introductory Remarks

Research on steady-state contingency evaluation methods has yielded a wide spectrum of computational approaches whereby rational comparisons can be made on the basis of (a) computational speed, (b) computational storage requirements, and (c) solution accuracies. Various modeling assumptions are made for each approach. In each case, however, the interest is in predicting line loadings, and possibly, voltage and various levels in the network under consideration, following single or multiple line outages or single generator outages.

*This comparison is primarily subjective based on the writers' experience and published literature.

TABLE II. Comparison of Six State Estimation Methods

METHOD	ACCURACY	MEASUREMENT SYSTEM	COMPUTATIONAL SPEED RANKING	CORE STORAGE RANKING
1. SSE	Suboptimal	Mixed	1 or 2	1
2. AEP	Suboptimal	Line Power Flow Only	1 or 2	2
3. Modified AEP	Suboptimal	AEP + KV + Line Currents	3 or 4	3
4. Decoupled WLS	Optimal	Mixed	3 or 4 or 5	5
5. WLS	Optimal	Mixed	6	6
6. GLF	Suboptimal	Mixed	4 or 5	4

In either case, a pre-outage "state" should be available (e.g., base-case load flow solution). For line outages, assumptions pertaining to the load flow problem are retained. And for generator outages, assumptions related to the redistribution of lost generation among the remaining generators are used.

Line outages produce a significant change in the network parameters of the problem. Assuming that the pre-outage case is given by

$$f(x,p) = 0 \tag{1}$$

where x is the vector of state variables (complex bus voltages) and p is the vector of network parameters, then the post outage case is given by

$$f(x + \Delta x,\ p + \Delta p) = 0 \tag{2}$$

where Δp represents the change in p due to the outage and Δx is the resulting change in x. Here $f(.,.)$ corresponds to the system's power flow equations. Invariably, all contingency evaluation algorithms follow either (or a combination) of the following approaches:

(a) Sensitivity Analysis

Here one writes,

$$f(x+\Delta x,\ p+\Delta p) \cong f(x,p) + (\partial f/\partial x)|_{x,p}\Delta x + (\partial f/\partial p)|_{x,p}\Delta p \tag{3}$$

and by implication, one writes:

$$\Delta x \cong -(\partial f/\partial x|_{x,p})^{-1}(\partial f/\partial p)|_{x,p}\Delta p \tag{4}$$

(b) Improved Sensitivity Analysis

In this case, it is assumed that the Δp is not small. Hence, one writes:

$$f(x+\Delta x,\ p+\Delta p) \cong f(x,\ p+\Delta p) + (\partial f/\partial x)|_{x,p+\Delta p}\Delta x \ . \tag{5}$$

This leads to the solution:

$$\Delta x \cong (\partial f/\partial x|_{x,p+\Delta p})^{-1} f(x,\ p+\Delta p) \ . \tag{6}$$

In either of the above approaches, simplifications (or approximations) are made regarding the load flow equations, $(f.,.)$, the Jacobian matrix, $\frac{\partial f}{\partial x}$, or both. In the ac methods this permits the use of additional iterations to improve solution accuracy.

The major factor which makes this approach computationally efficient is the so-called Matrix Inversion Lemma, which in equation form is stated as follows:

$$(A + CD^T)^{-1} = A^{-1} - A^{-1}C(I_m + D^TA^{-1}C)^{-1}D^TA^{-1} \tag{7}$$

where

$A \triangleq$ nxn non-singular matrix

$C,D \triangleq$ nxm matrices (normally $m=1$, or $m \ll n$)

$I_m \triangleq$ mxm identity matrix.

Thus, the problem of inverting $(A + CD^T)^{-1}$ simplifies to that of inverting an mxm matrix provided A^{-1} is available. In most cases, however, the triangular factors of A are used within a scheme of sparse matrix computation.

The solution of a generator outage case is computationally simple. Here, the post-outage power flow equations can be written as:

$$f(x + \Delta x, p) = \Delta S \tag{8}$$

where ΔS represents the change in net power injections due to the outage. Δx is obtained by means of one or more iterations of the type

$$\Delta x = -(\partial f/\partial x)^{-1}|_{x,p}\Delta S \ . \tag{9}$$

The difficulty, however, is in the evaluation of ΔS itself. The following schemes provide certain possibilities:

(a) Redistribute lost generation among remaining generators by means of "participation factors" and iterate if slack generation turns out to be too excessive;

(b) Redistribute generation according to the economic dispatch criterion;

(c) Allow slack bus to absorb lost generation, or

(d) Redistribute lost generation among the remaining AGC generators according to their participation factors. If more MW capacity is needed than is available by AGC, exit from program: "System Insecure."

Thus, the main difficulty here is in adequately representing steady-state response following a generator outage without excessive data requirements.

B. Comparison of Line Outage Methods

In the bibliography, we have tried to refer to most known outage methods. For purposes of comparison, however, six representative methods were selected. These are:

1. Distribution Factors Method (DF)
2. Exact DC Outage Analysis (EDC)
3. Z-Matrix Method (ZM)[159]
4. Stott's Decoupled Load Flow (SDLF)[167]

TABLE III. Summary of Single Branch Outage Procedures of Various Schemes

# METHOD	MODEL	REPRESENTATION OF LINE i-j OUTAGE	CHANGE IN FLOW ON LINE k-ℓ, OR, CHANGE IN STATE VARIABLES	SOLUTION METHOD
1 Distribution Factors (DF)	DC Load Flow $A\theta = P$	$A \to A - \frac{1}{X_{ij}} e_{ij} e_{ij}^T$	$\Delta T_{k\ell} = \frac{1}{X_{k\ell}} e_{k\ell}^T A^{-1} e_{ij} T_{ij}$	Sensitivity Analysis
2 Exact DC Outage Analysis (EDC)	DC Load Flow $A\theta = P$	$A \to A - \frac{1}{X_{ij}} e_{ij} e_{ij}^T$	$\Delta T_{k\ell} = \frac{1}{X_{k\ell} D_{ij}} e_{k\ell}^T A^{-1} e_{ij} T_{ij}$ $D_{ij} = 1 - \frac{e_{ij}^T A^{-1} e_{ij}}{X_{ij}}$	Improved Sensitivity Analysis
3 Z-Matrix Method (ZM)	$ZI = E$ with no load impedances and E initialized at base-case solution	$Z^{-1} \to Z^{-1} - \frac{1}{Y_{ij}} e_{ij} e_{ij}^T$	$\Delta(E_k - E_\ell) = \frac{y_{ij}(E_i - E_j) e_{k\ell}^T Z e_{ij}}{1 - y_{ij} e_{ij}^T Z e_{ij}}$	Improved Sensitivity Analysis
4 Stott's Decoupled Low Flow (SDLF)	$\frac{\Delta P}{V} = B'\Delta\theta$ $\frac{\Delta Q}{V} = B''\Delta V$ (Approximate Jacobian)	$B' \to B' - B'_{ij} e_{ij} e_{ij}^T$ $B'' \to B' - B''_{ij} e_{ij} e_{ij}^T$	$\Delta\theta = \frac{(B')^{-1} e_{ij} e_{ij}^T (B')^{-1} \frac{\Delta P}{V}}{\frac{1}{B_{ij}} - e_{ij}^T (B')^{-1} e_{ij}}$ $\Delta V = \frac{(B'')^{-1} e_{ij} e_{ij}^T (B'')^{-1} \frac{\Delta Q}{V}}{\frac{1}{B''_{ij}} - e_{ij}^T (B'')^{-1} e_{ij}}$	Improved Sensitivity Analysis (may require two $(\Delta\theta, \Delta V)$ iterations)
5 Iterative Linear Load Flow (ILLF)	$A\theta = P' + P''$ $CV = Q' + Q''$ (Approximate AC Load Flow P', P'', Q', and Q'' are Taylor Series Expansions)	$A \to A - A_{ij} e_{ij} e_{ij}^T$ $C \to C - C_{ij} e_{ij} e_{ij}^T$	$\Delta\theta = \frac{A^{-1} e_{ij} e_{ij}^T A^{-1}(P' + P'')}{\frac{1}{A_{ij}} - e_{ij} A^{-1} e_{ij}^T}$ $\Delta V = \frac{C^{-1} e_{ij} e_{ij}^T C^{-1}(Q' + Q'')}{\frac{1}{C_{ij}} - e_{ij} C^{-1} e_{ij}^T}$	Improved Sensitivity Analysis (may require more than one iteration)
6 Sachdev-Ibrahim Method	Full AC Power Flow	Compensate for outage by injecting real and reactive powers at busses i and j. Denote compensation by $\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}$ (Note $\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}$ has only four nonzero components)	$\begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} = \left(\frac{\partial f}{\partial x}\Big\|_{x,p}\right)^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix}$	Combination

Definitions:

$$e_{ij} = \begin{bmatrix} 0 \\ 0 \\ \vdots \\ 1 \\ 0 \\ -1 \\ 0 \end{bmatrix} \begin{array}{l} \\ \\ \\ \leftarrow \text{ith row} \\ \\ \leftarrow \text{jth row} \\ \\ \end{array}$$

; $T_{ij} \triangleq$ real flow on line i-j ; $Z \triangleq$ nodal impedance matrix with no shunt terms and with shunt impedance at slack bus = 1+j1 ; E = vector of nodal voltages

5. Iterative Linear Load Flow (ILLF)[166]
6. Sachdev-Ibrahim Method (SIM)[172]

In Table III, a summary is provided regarding the numerical schemes involved. Methods 2-5 make use of the Matrix Inversion Lemma while Method 1 is strictly a sensitivity analysis method and Method 6 is a "compensation-type" method. Table IV provides a comparison of these methods from the computational, data requirements (type of security monitor), and output characteristics points of view. In comparing computational speed requirements two alternative regimes were assumed:

1. The inverses of matrices are stored as as such. This is normally true for DF, EDC, and ZM methods.
2. Only triangular factors of matrices are stored. This is normally true for SDLF, ILLF, and SIM methods.

The argument for storing the inverses as such is that system operators can restrict the study system to those lines which tend to overload as well as those that cause the overload. The computational gain in speed is of the order of 100:1 over the regime of storing triangular factors only.

2.1.3 Contingency Evaluation Modeling Requirements

The minimal and intermediate forms of the security monitor provide information on the so-called internal system with little or no reference to the external system (part of which may belong to the utility under consideration). In order to perform contingency analysis, however, an equivalent representation of the external system is necessary.

The classical approach to static network equivalents consists of the following steps:

(a) Define as boundary buses those internal system buses which are connected to the external system.

(b) Eliminate all external system buses using the linear model of the nodal admittance matrix. This elimination creates an equivalent interconnection among the boundary buses which has the same form of a model admittance matrix.

(c) The original internal network plus the equivalent network form the basis for a power flow program. The boundary buses, here, retain their original classification as (P,V) or (P,Q) buses.

The main criticisms leveled against this classical approach are the following:

(a) The power flow problem is essentially nonlinear. Hence, a linear approach to equivalencing is, at best, an approximation. Experience has shown that very poor results are sometimes obtained.

(b) The external system may be very large (many thousands of buses) requiring considerable effort of data processing. Conceivably, a good portion of that system has no impact on the internal system.

(c) Boundary buses consist of a combination of the old boundary buses and all of the eliminated buses. There is no reason to believe that the old (P,V) or (P,Q) classification remains valid after the reduction.

(d) Certain utilities have large numbers of boundary buses. The equivalencing process will create large numbers of interconnections among these buses with each boundary bus connected to every other boundary bus. Computationally, the system matrices become highly non-sparse. This is detrimental to computational speed and storage requirements.

The advantages of this equivalencing approach are:

(a) Simplicity; and

(b) The retained system is always observable (by the security monitor). Hence, a base-case solution for contingency analysis will be available.

Researchers have tried to overcome some of the problems involved in the classical approach. Following is a discussion of some of the reported research:

(a) Approach of Ref. (184): In this approach the classical network reduction method is retained. However, prior to the reduction, a substantial portion of the external system is simply removed. The criterion here is that all flows to the removed system are positive. This maintains a net generation surplus in the retained part of the external

TABLE IV. Comparison of Computation Characteristics of Line Outage Methods

METHOD	ACCURACY RANKING	SPEED RANKING (1)	SPEED RANKING (2)	STORAGE RANKING	SECURITY MONITOR	SPECIAL FEATURES
(DF)	6	1	1	1	Minimal	Linear; Real Powers Only
(EDC)	5	2	2	1	Minimal	Real Powers Only
(ZM)	4	3	3	3	Minimal or Intermediate	Complex Flow Only No KV Prediction
SDLF	3 (one iteration only)	4	4	4	Intermediate	Complete ac Prediction
ILLF	2 (1½ iteration)	4	4	4	Intermediate	Complete ac Prediction
SIM	1	6	6	6	Intermediate	Complete ac Prediction

system. Portions of the external system are retained within the internal system representation in order to improve solution accuracy. The main drawbacks here are that the state estimator should be extended to a neighbor's utility. Furthermore, sparsity can be still sacrificed.

(b) Approach of Ref. (187): Studies on a particular system showed that boundary nodes are best represented as (P,V) nodes. This prompted the analysis of two alternatives. In the first, the equivalent system is solved with all boundary nodes classified as (P,V) nodes. And in the second, the external system is represented by the linear DC power flow model. In turn, this linear system, rather than the admittance matrix, is eliminated. The main difficulty here is that the (P,V) classification is system-dependent. Furthermore, sparsity is still sacrificed if the boundary nodes are numerous.

(c) Approach of Ref. (186): The main concern here is the sparsity of the equivalent network. It is shown that by retaining a portion of the external nodes in the equivalent considerable savings in computer storage and execution times is possible. Obviously, this may require an extension of the domain of the state estimator.

Aside from the above discussion, a significant problem remains. In the minimal and intermediate security monitors very sketchy on-line information is available about the overall external network. A non-valid equivalent can provide very inaccurate information in contingency analysis. Some preliminary effort to overcome this difficulty has been reported in Ref. (188). Here the equivalent is identified as using on-line data from the internal system. However, there are no reported test results on these efforts. Efforts to achieve valid equivalents by means of adequate inter-utility data exchange, thus eliminating the need for identification, have not yet succeeded.

2.2 Transient and Dynamic Stability Security Assessment

2.2.1 Introduction

Transient stability assessment consists of determining if the system's oscillations following a short circuit fault will cause loss of synchronism among generators. The primary physical phenomenon involved here is that of inertial interaction among the generators as governed by the transmission network and bus loads. This phenomenon is of short duration (1-3 seconds) in general. For longer durations the dynamics of boilers, turbines and other power plant components cannot be ignored. Coupled with that is the control action of impedance and underfrequency load shedding relays. As a result, the effect of a fault-initiated disturbance may continue past the transient stability phase to the so-called long-term dynamic stability phase which can be of the order of 10-20 minutes or more. Serious blackouts that have occurred over the past 15-20 years were generally the result of long-term instability and sequences of cascading events. The events causing these blackouts are given in Ref. (238), and can be classified into the following:

(a) Faults on lines when other system components are out for maintenance;

(b) Loss of generation causing overloaded inerties;

(c) Operator initiated errors;

(d) Relay malfunction or inadequate relay settings.

Transient stability analysis is much easier to conduct than long-term dynamic stability analysis both in terms of modeling requirements and the duration of system response times. As will be shown below, this has serious implications in regard to data base requirements and on-line implementation. In the discussion below transient stability assessment is first considered with emphasis on numerical solution techniques and the problem of dynamic equivalents. Following that, approaches to long-term dynamic stability analysis are discussed.

2.2.2 Transient Security Assessment

A. System Modeling Requirements

Each generator is represented electrically as a constant voltage source behind is transient reactance. Loads are represented as constant impedances or constant load currents which are determined from pre-fault load flow conditions. System dynamics are represented by the generator second-order torque equation assuming constant mechanical inputs. Mathematically one writes

$$M_i \frac{d^2\delta_i}{dt^2} + D_i \frac{d\delta_i}{dt} = P_{M_i} - P_{E_i} \quad ,$$

where

i = ith generator index.

M_i, D_i = generator inertia and daming constants, respectively

δ_i = rotor angle relative to the synchronous reference

P_{M_i} = constant mechanical input

P_{E_i} = electrical output

All electrical outputs and loads are represented by load-flow equations or linear voltage-current equations.

For this mode, pre-outage on-line data requirements consist of

(a) Voltage magnitudes and angles at all buses (state estimates)

(b) Status of all units

(c) Unit constants

(d) Network characteristics

(e) Fault type, duration and location.

Thus, an intermediate type security monitor will be adequate provided the external system is properly modeled by a dynamic equivalent.

Models of higher degree of complexity than the above are sometimes desired and used. This may include

- Excitation system model,
- Detailed generator electrical model,
- Governor control model, and
- Turbine models.

B. Stability Analysis

Two primary approaches are used in the literature to perform transient stability analysis: numerical integration and the use of Lyapunov's method. Practically, however, numerical integration is the only method used.

Several numerical integration approaches have been proposed and used. They generally fall under the categories of implicit or explicit methods.(218) As in all integration schemes, the usual limiting factor is the smallest time constant of the system which is caused normally by synchronizing oscillations. The use of implicit predictor-corrector methods has generally allowed larger step-sizes while maintaining a high level of numerical stability.(216) Normally, the transient stability program will alternate between an integration step and a load-flow solution to solve the network equations. Thus, sparse matrix methods can be quite effective and useful in this context.

Attempts to by-pass the limitations of synchronizing oscillations have been made in the Dynamic Energy Balance approach.(255) Here, a modeling assumption is introduced assuming coherency among tightly coupled generators. By implication, each coherent group is represented by a single inertia equation by neglecting all synchronizing oscillations within the group. This permits the use of longer integration step-sizes and the prediction of system conditions over periods of 20 seconds or so. The drawback of this approach is that coherent areas cannot be determined in advance always.

In order to improve on the computational speed requirements of direct integration Lyapunov's stability methods for power systems were developed. This involves the derivation of a scalar Lyapunov function $V(x)$, where x is the dynamic state vector of the system's set of differential equations, which has the following properties

$V(0) = 0$, i.e., $x = 0$ is the equilibrium state

$V(x) > 0, \ x \in \Omega \ , \ x \neq 0$

$\frac{dV((t))}{dt} \leq 0, \ x \in \Omega$

where Ω is a region around the stable point $x = 0$, which is called the region of stability. It can be shown that if, due to a fault, $x \in \Omega$ (but $x \neq 0$) then $x \to 0$ as $t \to \infty$. In Ref.'s (221-234) various forms of the Lyapunov function were derived. The main difficulty here is that determination of the boundary of the stability region is very difficult numerically. In a recent paper(234) it is claimed that such a difficulty can be overcome. However, this remains to be demonstrated on a large-scale system.

The advantages of Lyapunov's method, once the above obstacle is cleared, are:

(a) It can determine quickly if a system is stable directly from the post-fault condition.

(b) It can provide a measure of the margin of stability for given fault conditions.

The drawbacks of the method are:

(a) It cannot predict instability. Thus it may produce too many false alarms.

(b) The Lyapunov function depends strongly on the dynamic model chosen. Any increase in modeling complexity may invalidate the approach. For example, it has been reported that the inclusion of network line conductances is detrimental to the method. In fairness, however, many Lyapunov functions have been obtained in which machine saliency and governor action are represented.

C. Dynamic Equivalents

As in the steady-state case, an equivalent representation of the external system is necessary. A good dynamic equivalent should have the following properties:

- provide accurate and reliable post-fault predictions within the internal system;
- be computationally efficient;
- require minimal on-line information from the external system.

Methods of generating dynamic equivalents are grouped into two classes: those based on coherency and those based on linear modal analysis. The coherency methods are based on the empirical/heuristic assumption that generators tend to swing together in coherent groups. A coherent group can be represented by one equivalent generator or a group of generators which maintain among themselves constant rotor angle differences. On the other hand, modal analysis is a mathematical approach based on linearlizing system's differential equations, performing eigenvalue analysis and discarding the irrelevant modes (e.g., those which dampen very quickly).

Coherency based methods differ from one another in a variety of detailes like

- methodology of selecting coherent groups,
- methods of connecting the equivalent machine to the original machine nodes, and
- methods of equivalencing exciter, turbin, and governor dynamics.

Reference (259) contains a comprehensive discussion of several dynamic equivalencing methods and proposes an automated approach for that purpose. The only drawback of this approach is that the equivalent is a function of fault location. However, it has the advantage of predicting instabilities in the external system among the equivalent generators. And this is not the case with the modal approach.

The main conclusion about dynamic equivalents is that there are distinct advantages in an automated equivalencing approach for on-line as well as off-line studies. However, some problems related to dependency of the equivalent on fault location remain to be solved. Furthermore, validation of the results using actual system measurements has not been attempted yet.

2.2.3 Long Term Dynamic Response Assessment

The bojectives of this type of assessment are:

- Evaluation of dynamic reserve response characteristics including distribution of reserves and effect of fast starting units;
- Evaluation of emergency control strategies like load shedding by underfrequency relays, fast valving, dynamic bracking, and others.

These objectives fall primarily under system planning, control system design, as well as, post-disturbance analysis. However, the operating implications cannot be neglected. As reported in Ref. (238), most of the major system disturbances in the past several years occurred under abnormal system conditions. On-lone dynamic response analysis, if feasible, can indicate to the operator the catastrophic risks involved with given contingencies. These risks are difficult to evaluate effectively by means of steady-state or transient analysis.

Two approaches to this problem have been investigated so far: the digital (238) and hybrid(220) computer approaches.

Advantages of the digital approach are:

- Detailed representation of power plant models, relay systems and control strategies is straightforward;
- Flexibility in changing system parameters or switching from one system to another;
- Relatively low cost of running programs on a general purpose computer.

Its disadvantage is in the computational time requirements which make the digital approach an off-line tool. The advantage of the hybrid approach obviously is computational speed which can be 100 times faster than real time of simulated process. The disadvantages are:

- Inflexibility in changing network and system parameters for on-line contingency analysis. However, serious attempts have been made to overcome this difficulty.(220)
- Complex modeling of the system can add appreciable investment costs in system hardware which may not be justified economically since the system will have to be dedicated for that purpose. However, a simple facility for transient analysis may be attractive.

In conclusion, both approaches may prove to be of significant value. The digital approach will continue to be indespensible in off-line analysis. And, with cost reduction breakthroughs in hybrid systems, on-line applications may yet result. In either case, however, model calibration and validation is still a major problem requiring a fair amount of investigative work.

2.3 Pattern Recognition Security Assessment

The main objective of pattern recognition security assessment is to reduce on-line data and computational requirements to a minimum. This is done at the expense of elaborate off-line computations. The original suggestion for using pattern recognition came from DyLiacco(16) who proposed a deterministic as well as a schochastic approach to the problem. Further research as later reported in Ref.'s (283-289).

The classical methodology of pattern recognition consits of defining a pattern vector x whose components consist of all the significant variables of the system. This vector is evaluated at many representative operating conditions to generate what is termed the training set. Since many components of the pattern vector will be strongly correlated with one another, a process of dimensionality reduction is performed to identify significant and, hopefully, uncorrelated set of variable $z_1,\ldots,z_m$ which are functions of the components of x. Hopefully the vector $z = (z_1,\ldots,z_m)^T$ is much smaller in dimension than x. This process is called feature extraction. The final step is to determine a function S(z) such that

$$S(z)\begin{cases}\geq 0 \text{ for a secure } z\\ < 0 \text{ for an insecure } z\end{cases}$$

This is called a security function. Several methods are available for generating S(z) based on the form S(z) is assumed to take. If S(z) is assumed to be linear in the linear programming or least-squares methods can be used. Nonlinear functions, like quadratic functions, or multiple functions can be used. Here least squares or optimal search methods have been successfully used. The main objective of these methods however, is to minimize the number of misclassifications especially when an insecure pattern is misclassified as secure. In Ref. (288) a bias term is added which yields false alarms but very few misclassified insecure patterns. Furthermore, different security functions can be developed for steady-state and transient security.

From reviewing the literature on the subject one obtains a mixed opinion. Several reported tests have shown successful results with a record of misclassification of the order of 1-10% depending on the complexity of S(z) and size of the training set. Results of failure have also been reported whereby it is argued that the computational effort to generate an adequate S(z) for a large system is impractical.(289)

From our point of view pattern recognition offers the following advantages:

- It can drastically reduce the requirements of on-line security analysis. All what is required is the computation of S(z) based on direct on-line measurements or state estimator outputs. This is particularly true in the case of transient security assessment where on-line computation is time consuming.
- The requirement that $S(z) \geq 0$, can be used as the security constraint in an on-line optimum power flow or for preventive as well as corrective control measures.
- The process of training can pinpoint weaknesses in the system that may pass unnoticed otherwise.

Disadvantages of the method are:

- Off-line computation may be too excessive
- S(z) may very well be sensitive to system configuration. Any scheduled or unscheduled outages may require the use of a different S(z). This can add a considerable computational burden.
- Pattern recognition can be construed as a form of extrapolation from the training set to the actual operating state. Since insecurity will arise as a result of abnormal operating conditions this extrapolation may give poor results.

2.4 Measures of Security

2.4.1 Objectives and Types of Security Measures

Contingency evaluation provides the main working tool to answer the various "what if" questions posed automatically or by the operator. A measure of security is intended to summarize the information resulting from many contingency checks in a simple form to be used by the operator as a guide for preventive control action.

In general two types of security measures have been proposed: deterministic and probabilitic. In the deterministic case listing of contingencies that may cause emergencies is provided to the operator, together with information on the security of each case. The operator will then decide what to do either through experienced judgement or by interrogating programs for corrective action. In the probabilistic case two approaches have been proposed:

(a) Security indices approach;

(b) Reliability analysis approach.

Discussion of these follows.

2.4.2 Security Indices

Ref. (263) contains a comprehensive analysis of the idea of security indices. It differentiates between steady-state and transient indices.

In the steady-state case consideration is given to the following indices:

- line and transformer MVA flow index
- bus voltage index
- generator reactive reserve index.

For each index type an index function f(x) is defined on a component by component basis. This function assumes the value of 1.0 when the corresponding component is operated within safe limits. It assumes monotonically decreasing values from 1.0 to zero as the range of component operation varies from the safe to the unacceptable limit. Beyond the unacceptable limit this function is zero. The form of this function between the safe and unacceptable limits is cubic, quadratic and linear for line, bus voltage and reactive reserves indices respectively. For each steady-steady contingency k the following index is computed

$$\bar{f}_k = \sum_{i=1}^{N} \omega_{ik} f(x_{ik}) \Big/ \sum_{i=1}^{N} \omega_{ik}$$

where i ranges over all relevant components (e.g., lines and transformers, or bus voltages, etc.) and ω_{ik} are weighting factor (e.g., line power flows for the line index). Finally for each index one computes

$$\bar{I} = \sum_{k=1}^{M} \alpha_k \bar{f}_k \Big/ \sum_{k=1}^{M} \alpha_k$$

where k ranges over all contingencies and α_k is the probability of occurance of that contingency.

Interpretation of the above approach based on judgement by its authors is summarized as follows:

- Choice of soft rather than hard constraints can account, at least heuristically, for the fact that violation of steady-state limits can be tolerated for a short time period which is normally of the order of a few minutes.
- The security index $\bar{f}$ although evaluated using certain probabilities, is not in itself the probability of system insecurity. It is only an index whose absolute value is dependent on system size.
- As a result of the above remark, the index becomes a starting point for more detailed analysis whereby the worst cases of limit violations are displayed to the operator.

In the case of transient security assessment reduction of the information in the form of an index is even more desirable than the steady-state case. The operator simply cannot cope with large numbers of swing curves. Again in Ref. (263) two types of transient security indices are proposed:

(a) Maximum angle separation index;

(b) Apparent impedance index.

The maximum angle index is given by

$$\hat{\theta}_k = \underset{t}{\text{Max}}\ \underset{i,j}{\text{Max}}\ \theta_{ijk}(t)$$

where $\theta_{ijk}(t)$ is the angular separation between generation i and j at time t due to fault k. Obviously, if $\hat{\theta}_k \geq 180°$ instability would occur. Normally $\hat{\theta}_k$ is limited to a certain maximum which depends on the system ($\theta_{max} \simeq 180° - 200°$). A contingency swing factor σ_k is defined such that

$$\sigma_k = \begin{cases} 1 \text{ if } \hat{\theta}_k \rightarrow 0 \\ 0 \text{ if } \hat{\theta}_k \rightarrow \theta_{max} \end{cases}$$

Subsequently, a composite transient stability index is defined considering all contingencies.

In the apparent impedance index, one evaluates

$$Z_{ij} = \frac{V_i}{I_{ij}} = \frac{V_i}{(V_i - V_j)} z_{ij}$$

which is the apparent impedance "seen" by relay at terminal i of line i-j. A more appropriate quantity is

$$Z^*_{ij} = \frac{Z_{ij}}{z_{ij}}$$

Loss of synchronism will occur whenever Z^*_{ij} would cross the line segment [0,1]. Based on this, a contingency swing factor σ_K for the kth contingency can be defined:

$$\sigma_K \rightarrow 0 \text{ as } d_K \rightarrow 0$$

$$\sigma_K \rightarrow 1 \text{ as } d_K \rightarrow \infty$$

where d_K is the distance of Z^*_{ij} from the segment [0,1].

2.4.3 Reliability Analysis Approach

Application of reliability analysis methods to on-line security assessment was originally attempted in the evaluation of spinning reserve requirements as a function of the near-time future.(272) System contingencies consisted of load forecasts and their uncertainties as well as generator outages described by outage probabilities. A risk function is defined as the probability of insufficient generating capacity and is illustrated in Fig. 3. In this figure it is assumed that at t = 0, the risk is zero. As t increases, the load increases causing smaller reserve margins and a non-zero probability of insufficient reserves. At $t = t_R$, a reserve unit is added and obviously this decreases the risk instantaneously as shown. The decision to add the reserve unit at t_R

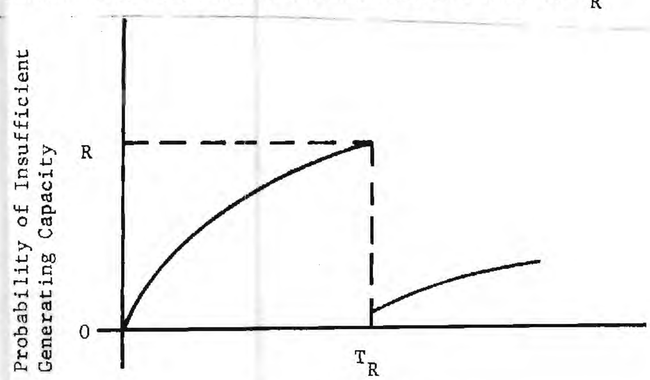


Figure 3. Variation of System Risk with Time into Future(272)

depends on exceeding the minimum risk level R. This level is decided upon by operational experience. Further elaborations upon this approach considers the inclusion of standby generators of different start-up response times. Start-up failures are included in a Markov-type model to represent more accurately the various risk probabilities. A key formula which is developed here is a security function defined by

$$S(t) = \sum_i P_i(t)\, Q_i(t)$$

where $P_i(t)$ is the probability that the system is in state i at time t and, $Q_i(t)$ is the probability that state i constitutes a breach of system security.

This idea of a security function is used in Ref. (341) in conjunction with on-line system security optimization. In that reference the following function is defined

$$S(\underline{g}) = \sum_{\ell} P[\text{Line } \ell \text{ Overload} \mid \text{No Outages}]P[\text{No Outages}]$$

$$+\sum_{K}\sum_{\ell} P[\text{Line } \ell \text{ Overload} \mid \text{Line k Out}]P[\text{Line K Out}]$$

$$+\sum_{j}\sum_{\ell} P[\text{Line } \ell \text{ Overload} \mid \text{Gen. j Out}]P[\text{Gen. j Out}]$$

The availability of the system is given by

$$a = 1 - S(\underline{g})$$

In the evaluation of $S(\underline{g})$ load uncertainty for the next instant is accounted for by means of normally distributed random vectors with appropriate means and standard deviations. An acceptable availability limit a^* is established. And this becomes the basis for preventive or corrective action via security-constrained optimization.

2.5 Security-Constrained Optimization

Security constrained optimization consists of solving the problem of the allocation of generation subject to

(a) power flow constraints - equalities

(b) operating constraints - inequalities, and

(c) security constraints - inequalities.

While minimizing a performance criterion which is usually, but not necessarily, the cost of generation. Historically, an approximate form of the equality constraints has been (and is still being) used in conjunction with Economy Dispatch with a loss formula.

The availability of on-line state estimation now permits the use of load-flow equations directly as equality constraints. Furthermore, efficient security analysis programs permit the computation of security constraints either in the form of operating limit violations following a contingency or in the form of security functions.

Table V provides a summary comparison of a sample of security constrained optimization methods. A few remarks are in order regarding this table.

(a) Method No. (3) makes a distinction between a "global" and a "local" system security. In the global case all security constraints are satisfied. In the local case, allowance is provided for short-term (15 min.) violations of line loading limits since the thermal limit is not reached instantaneously.

TABLE V. Comparison of a Sample of Methods of Security Constrained Optimization

METHOD	PERFORMANCE CRITERION	SECURITY CONSTRAINTS	SOLUTION METHOD
1. Ref. (311) Kaltenbach	Combined Economic and Load Shedding	Linearized, Single Line Contingencies Only	Linear Programming
2. Ref. (337) Alsac	Generation Cost	Single Line Contingencies	Penalty Function
3. Ref. (328) Carpentier	Generation Cost	Single Line Contingencies and Generation Reserve	Generalized Reduced Gradient (GRG)
4. Ref. (329) Carpentier	Production Cost Over a Period (e.g., One Day)	Single Line Contingencies Generation Reserves (Unit Committment)	GRG + Branch and Bound Optimization
5. Ref. (339) Wollenberg	Generation Cost	Minimum Availability Guaranteed (Security Function based on Reliability	Max - Min Optimization
6. Ref. (340) Sachdev	Insecurity Function	Single Line Contingencies	Non-Linear Programming

(b) Method No. (4) discusses the important topic of security constrained operational planning by incorporating the unit committment problem into the formulation.

(c) Method No. (5) provides a novel approach based on reliability analysis and the "inconvenience level" associated with power outages.

(d) Method No. (6) emphasizes the point that when the system becomes vulnerable, the economic criterion may have to be ignored and replaced by a strictly security criterion.

In one respect security constrained optimization is an attempt to replace the operator as much as possible, by maintaining the system in the Secure Normal State as long as possible. It thus combines security assessment and enhancement. However, this is still costly from the computational viewpoint.

3. CRITICAL ASSESSMENT AND RECOMMENDATIONS

In our opinion, the main considerations in further progress in the security assessment process are:

(a) methodologies to reduce computational requirements;

(b) cost of insecurity, or the risk involved in insecure operation;

(c) accuracy and reliability of the analysis effort;

(d) role of the operator;

(e) interconnected system security assessment.

The remaining part of this section is devoted to brief discussions of these items.

3.1 Methodologies to Reduce Computational Requirements

As has been shown earlier, considerable effort has been, and continues to be spent on developing very efficient digital algorithms (and hybrid systems) to reduce the time required for contingency analysis. In spite of this, a complete security assessment process based on frequent steady-state and transient contingency analysis is either impossible or impractical with present systems. Various possibilities to overcome this are suggested:

(a) Predictive security assessment

With the aid of bus load forecasting(143) one can perform the following function

- planning of secure operations involving unit committment, generation and tie-line scheduling, and scheduling of maintenance outages. This may also involve the monitoring of key quantities.
- predictive secure operation for the next hour or so involving the identification of critical outages that need to be monitored closely.

(b) Pre-screening computation

Fast and approximate algorithms can resolve the issue for many contingencies that are trivially secure. The more accurate algorithms will, consequently, be called upon less frequently. For example, the distribution factors method can be used to pre-screen contingencies for the more accurate ac methods. Similarly, steady-state analysis can pre-screen cases for transient analysis by considering steady-state stability limits. This will require an analysis of how much information can be derived from various types of analysis. And this can be the basis for a sequential pre-screening process.

(c) Stochastic power flow analysis

Stochastic power flows(141,142,144,154) can be put to good use in determining margins of uncertainty, and consequently, the probability of insecurity. This has been achieved in Ref. (339) in computing a probabilistic measure of security. The use of stochastic load flows is pertinent in conjunction with predictive analysis both for next hour or next day forecasting.

3.2 Cost of Insecurity

Reliability analysis can be put to good use in predicting the probability of system interruptions, given a computational methodology. This has been successfully applied in generation capacity planning whereby an acceptable risk of insufficient generation is assumed. This risk is based on accepted reliability standards and econimc considerations.

The cost of an outage causing a blackout can be measured in terms of

- lost energy serviced;
- inconvenience and possible danger to the public;
- embarassment by utilities;
- security of the blackout; and
- frequency of occurance.

If quantifiable, such factors can be introduced in computing the cost of insecurity. For example, one can express such cost as:

$$C_I = \sum_i P_i \, G_i$$

where C_I is defined as the cost of insecurity, P_i is the probability of the ith outage and G_i is the cost associated with the outcome of that outage. The cost associated with the outage of the outage will depend on any of the following factors:

- Availability of post-outage corrective control measures--for thermal limit violations a minimum time of a few minutes is available for correction. For transient stability cases, measures such as dynamic breaking, fast valving and capacitor switching may also be available. In such cases the cost associated with limit violations may be quite small.
- Possibility of cascading events. Here dynamic stability may be involved requring, at least, a gross estimate of the resulting effects. Modeling of load-shedding logic may be of value in this case. At any rate, the cost associated with the limit violation will be very high.

Once, this cost criterion is established, it can be used directly in the security constrained optimization program or in the interactive operator display by showing him the costs associated with serious limit violations.

3.3 Accuracy and Reliability of the Analysis Effort

In Table VI a summary is provided for various elements of inaccuracy in on-line security assessment and, methods for accuracy improvement and their status. From this table it is obvious that the major bottlenecks to reliable security assessment are:

(a) External network status

(b) External network equivalent representation

(c) Parameters of lines and transformers

(d) Component models of dynamic system

(e) Dynamic equivalent representation.

In order to combat the effects of such bottlenecks the following steps seem to be necessary.

- Assessment of the extent of inaccuracies in various models in terms of probability distributions or, simply, standard deviations.
- Analysis of the impact of such inaccuracies on security assessment results.(62) Seemingly large inaccuracies may have little impact on such results. On the other hand, small modeling errors in some cases may be detrimental.
- Study of combined hardware/software approaches to eliminate the impact of these inaccuracies. Conceivably, on-line information exchange among neighboring utilities may become necessary. The study will help in minimizing to costs of such endeavors.

Based on the above, the following comments are in order:

- A redundant measurement system coupled with state estimation software can provide most of the data needed for the above studies. This is not the case with a minimal data base system.

TABLE VI. Analysis of Errors Arising in the Security Assessment Effort

Quantity and/or Item	Error Estimates	Improvement Method(s)	Status of Improvement Method
On-Line Measurement			
(a) Normal Errors	5-2% of Scale	Measurement Redundancy with State Estimation and Bad Data Rejection	Adequate
(b) Bad Data	Unknown		
Network Topology			
(a) Internal System	Small	Model Correction Logic	Experimental
(b) External System	Large	(a) On-Line Information Exchange	Inadequate
		(b) Model Correction by Internal System	Experimental
Network Parameters			
(a) Internal System	5-10% of Value	(a) Parameter Estimation	Adequate
		(b) Manual Adjustments	Unknown
(b) External System	5-10% of Value	Parameter Estimation	Experimental
Dynamic Models	Considerable	(a) Individual Component Modeling	Adequate
		(b) Parameter Estimation	Experimental
Static Equivalents	Medium-Large	(a) Engineering Judgement	(a) Adequate for Planning
		(b) New Models	(b) Experimental and System Dependent
		(c) Parameter Estimation	(c) Experimental
Dynamic Equivalents	Large	(a) Heuristic-Automated	Experimental
		(b) Parameter Estimation	Experimental
Bus-Load Forecasting (1-24 hours)	1-5%	Different Statistical Methods and Good Weather Forecasts	Experimental

- The methodology of parameter estimation is a strong contender in providing statistically validated models for on-line use.
- The methodology of shochastic load flow is significant in providing with a quick summary of system statistical errors. This makes possible an effective use of bus load forecasting in predictive security analysis.
- Engineering ingenuity is still indespensible in providing new approaches and in interpreting results.

3.4 Role of the Operator

The advantages of the operator over automated software systems are:

- He relies on a global perception of events in interpreting results;
- He can take into consideration peculiar situations not originally programmed;
- He can be trained to assess the impact of a given contingency;
- He can override the computer when the results are unreasonable.

Obviously his main disadvantage (or limitations) are:

- Slow reaction time;
- Judgement is dependent on training and intellegence of particular operators;
- Knowledge of software capabilities and limitations is operator-dependent.

Table VII provides a summary comparison of the overall relative roles of the operator vis-a-vis the software system. In essence, we see the operator as being in the position to interrogate and then judge the system. The interrogation and judgement can take the following forms:

(a) Simple--contingency checking and listing of limit violations for "critical" contingencies;

(b) Interpretive--assess dollar (or other)costs of a preventive control measure;

(c) Objective seeking--input performance indices for optimization programs and then interpret results;

(d) Assess credibility--override software recommendations.

3.5 Interconnected System Security Assessment

This is a topic of increased significance due to the fact the causes of insecurity can originate outside the study system. Topics of particular interest here are:

(a) Availability and distribution of reserves (spinning and otherwise) in the interconnection;

(b) Power transfer capabilities on the inerties during the following emergencies;

(c) Identification of external events that are detrimental to internal system security.

In our opinion, an adequate data abase for interconnected system security is required. It should be based on on-line information exchange. Guidelines for secure operation should be established especially when security and economy of operation are in conflict with one another.

TABLE VII. Comparison of Operator vs. Software Roles in Security Assessment

Function	Operator's Role	Software Role
Contingency List Selection	Generate or Augment List	Generate List Based on Operations Planning
Probability of Contingency	Modify on Basis of System and Weather Conditions	Compute on Basis of Historical Data
Cost of Insecurity for Given Contingency	Interpret Simulation Result	Identify Possibilities
Impact of Contingency on System	Determine if Further Analysis is Required, e.g., Transient or Dynamic	Summarize Simulation Results in Adequate Form
Need for Corrective/ Preventive Action	Recommend Corrective/ Preventive Control	Compute Necessary Controls

APPENDIX A

Recommendations of the Federal Power Commission and of NAPSIC

The Northeast blackout of November 9-10, 1965, brought the utility systems of the country to the realization that a degree of vulnerability did exist, and that something should be done about the situation. The Federal Power Commission (FPC) began its study, and in July 1967 released its report on that subject. NAPSIC, the North American Power Systems Interconnection Committee--only three years old at the time of the blackout--also began a new series of studies, and upgraded its Operating Guides to provide more emphatic protection of bulk power system security.

Most of the 34 Recommendations of the F.P.C. have been translated into action by the utility systems and power pool organizations in North America. The recommendations stress coordination at the regional level for both planning and operation and for research into the remaining difficult problems; strengthening existing transmission systems and planning future expansions to be secure against contingencies; providing secure standby power for generating units and their auxiliaries; upgrading relay protective schemes, communications networks and display and recording equipment; making more effective use of computers; upgrading the training of operating personnel; making greater use of preventive maintenance and inter-utility reporting of troubles; and preparing for national defense emergencies.

Several of the recommendations relate to security enhancement through controls such as load shedding and generator isolation; and one, No. 17, directly addresses the subject of security assessment. It reads as follows: "Control Centers should be provided with a means for rapid checks on stable and safe capacity limits of system elements. The necessity for isolating a line or substation or dropping a generating unit, either in an emergency or for planned maintainance, can result in major shifts in network power flows. Rapid security checks to determine that various elements will be operated under safe limits under such modified conditions are essential to prevent unsafe loading. Rapid security checks are now feasible through the use of digital computers."

This recommendation for on-line contingency analysis is being followed by a number of utilities, as reported in the body of this paper, and research into improved security monitoring is currently very active.

NAPSIC's Operating Guides, like the F.P.C.'s recommendations, stress operating procedures for proper and safe operation, and for inter-utility coordination. The individual items are much more detailed than those of the F.P.C.

Operating Guide No. 21, approved in January, 1974 discusses the subject of security monitoring. The Guide recommends making off-line studies to determine potential problem areas, and making pre-planned solutions available to dispatchers. It recommends monitoring and display equipment to call attention to dangerous situations, and suggests the exchange of vital operating data between utilities. Voltage should be monitored and voltage schedules centrally coordinated. More specifically, the Guide recommends that "Transmission line monitoring should include a means of evaluating the effect of loss of transmission or the loss of generation or loss of both transmission and generation. Scheduled outages of facilities should be taken into account in the monitoring scheme."

APPENDIX B

State of the Art of Security Assessment in the Utility Industry

In this appendix we report the results of a questionnaire which was mailed to some 60 utilities in the U.S. and abroad, on the question of security assessment. Following is an interpretation of our findings.

A. Responses from 8 Large (>10 GW) Utilities in the United States and Canada

-- None has implemented to satisfaction an on-line, continuous or frequent steady-state contingency analysis program using power-flow. However, two such utilities have implemented this program "with problems."

-- Only two are using distribution factors for contingency analysis.

-- Three are using power flow programs for off-line analysis of actual disturbances.

-- None has any present plans for an on-line transient security monitor, with or without interactive features.

-- Three are using transient analysis programs for off-line analysis of disturbances.

-- All are using transient analysis programs in the system planning process.

-- Seven are using automatic printout device for logging. One plans to add this capability in the near future.

-- Five now use input/output CRT display stations, and two others plan to do so in the near future.

-- Only one has implemented a form of security indices, and that one is experiencing problems.

-- There is a strong tendency to use a primary control computer for on-line monitoring and display functions, and to use a corporate computer for off-line studies.

-- Seven plan to utilize a state estimator and a bad data rejection program. The measurement redundancy ratios are from 1.5 to 2.9.

-- All have on-line tie-line power flow data, and half of this group have some on-line telemetering of some high-voltage line status, major generating unit status and spinning reserve in neighboring systems.

B. Responses from 28 Medium-Sized Utilities in the United States and Canada

-- Only two have implemented an on-line continuous or frequent steady-state contingency analysis program using power flow.

-- Three are now using similar programs but with distribution factors.

-- 18 use off-line power flows for post-analysis of disturbances.

-- Only one has attempted on-line analysis of contingencies involving transients. That one is satisfied with the program as implemented.

-- Eight utilize off-line transient analysis programs for post-analysis of disturbances.

-- Eleven use an automatic printout device for logging, and five more plan to do so in the near future.

-- Only 8 use CRT input/output stations for display, with only 4 having near-future plans for such use.

-- Three of these utilities have implemented to their satisfaction some form of security indices, and one plans to do so in the near future.

-- In this group there is a more general mix of using corporate, standby control and primary control computers for on-line monitoring and display, and of corporated, special-purpose and secondary control computers for off-line functions.

-- Not all of the respondants answered the questions about telemetered on-line data quantities. Of those who did, about 3/4 reported having on-line tie-line power flow data, while about half said they did have on-line information about some high-voltage line status, generator unit status and spinning reserve in neighboring systems.

C. Responses from 6 Utilities (Medium-Sized and Very Large) in Europe and Japan

-- Two have implemented to their satisfaction on-line continuous or frequent steady-state contingency analysis using power flow program.

-- None makes any present use of distribution factors.

-- Four have implemented off-line power flow programs for post-analysis of disturbances.

-- None has implemented any on-line program for transient analysis of contingencies.

-- Three utilize off-line transient analysis programs for post-analysis of disturbances, and four use these programs for system planning.

-- Four use automatic printout devices for logging and one more plans to do so in the near future.

-- Two have implemented CRT output monitors but none has an input/output CRT station.

-- One has satisfactorily implemented a form of security indices.

-- Most on-line monitoring and display is by primary and secondary control computers; off-line analysis is performed by secondary control computers and by corporate computers.

-- Three have definite plans to use a state estimator program, with bad-data rejection. They report measurement redundancy ratios in the range of 1.3 to 3.0

-- The replies to the questions about on-line telemetering were about the same as those from the North American utilities. Almost all have tie-line telemetering, while a somewhat smaller number reported having high-voltage line status, generator status or spinning reserve in neighboring systems.

D. Summary Evaluation of Utility Responses

-- Power flow programs are well developed and widely used for off-line studies, but problems are revealed when attempts are made to use them for on-line contingency analysis. The major obstacles probably are inadequate information about neighboring systems, and inadequate methods of producing static reductions of external networks. These obstacles combine to produce highly inaccurate results when the conditions in either the external or the internal network is drastically changed, as it is in contingency analysis.

-- Transient analysis programs also are well developed and are widely used for system planning studies even though their weaknesses are well known to most users. Only one utility reported successful use of an on-line transient contingency analysis program. It is safe to state that this usage is outside the present state of the art.

-- The use of distribution factors is rare, but the utilities which do use them are "satisfied." The state of the art in simulation has far surpassed these distribution factors, but perhaps their usefulness is inadequately appreciated. They provide "ball-park" results at low computational cost.

-- Security indices are well withing the state of the art, conceptually, but their usefulness is not yet proven.

-- State estimation has passed beyond the early R&D stage and some of the early myths about it have been dispelled. Still, only a few installations report much success. The concept is still in the vanguard of power system control technology.

-- Bad data rejection schemes and data-protective systems are now well developed and are used by any who have provided the economic justification.

-- Of the utilities planning to use state estimation in the near future, most prefer the method of weighted least squares, possibly because it is the easiest to understand.

-- Telemetering of information from the system's borders and beyond is well within the state of the art (both analog and digital). However, economic and other considerations inhibit the adequate development of inter-utility on-line data exchange systems.

-- For large systems, the major problems of operating the high-voltage grid are dynamic and transient stability. For medium-sized systems, the overwhelmingly most important problem is that of overloads. Other problems reported for this question were:

--System security
--Voltage and var balance
--Area Control
--Subsynchronous resonance
--Loss of customer loads
--Inadequate spinning reserve
--Short circuit levels
--Economics

System Security - General Works

1. C. P. Stienmetz, "Power System Control and Stability," AIEE Trans., 1920.

2. R. D. Evans and C. F. Wagner, "Studies in Transmission Stability," AIEE Trans., 1926.

3. I. H. Summers and J. B. McClure, "Progress in the Study of System Stability," AIEE Trans., 1930.

4. "Advisory Committee Report No. 6: Criteria for AC Transmission System Performance," FPC National Power Survey, pp. 45-47, 1964.

5. Richard Bauman, et. al., "The Main Factors of Influence in the Mathematical Modeling of Actual Conditions in Power Systems," ETZ-A Vol. 87, No. 32, Nov. 1966, pp. 818-823, Translated into English by approval of Bonneville Power Administration, c/o H. W. Dommel.

6. F. S. Brown, "Power Failures Caused by Sever System Disturbance," American Power Conference Proceedings, Vol. 28, April 1966, pp. 81-86.

7. P. Y. A. Kats, et. al., "Assessment of Power System Stability During Short Circuits," Energetika No. 7, 7, 1966, pp. 6-13 (in Russian).

8. U. G. Knight, "Linear and Dynamic Programming Methods in the Design and Operation of Electricity Supply Networks," Ph.D. Thesis, London University, Jan. 1967.

9. H. D. Limmer, "Security Applications of On-line Digital Computers," Presented at the Second Power Systems Computation Conference, Stockholm, June 27, 1966.

10. "Electric Power Reliability," Hearings before the Committee on Congress, United States Senate 19th Congress First Session No. S1934 Amending the Federal Power Act and Related Bills, Aug. 22, 1967.

11. L. T. Anstine, "Application of a Digital Computer to the Operation of the Pennsylvania-New Jersey-Maryland Interconnection," Proceedings of PICA Conference, 1967, pp. 109-116.

12. T. E. DyLiacco, "The Adaptive Reliability Control System," IEEE Trans. on Power Apparatus and Systems, Vol. PAS-86, No. 5, 1967, pp. 517-531.

13. R. K. Boyd, "Report on Manitoba Hydro System Security and Emergency Operation," CEA, Vol. 7, Part 3, paper 68, 1968.

14. C. Concordia, "Considerations in Planning for Reliable Electric Service," IEEE Spectrum, Vol. 5, No. 8, August 1968, pp. 71-76.

15. T. C. Cihlar, "Electric Utility System Security," American Power Conference Preprints, 1969.

16. T. E. DyLiacco, Control of Power Systems via the Multi-Level Concept, Case Western Reserve University Systems Research Center Report No. SRC-68-19, June 1968.

17. IBM Research Division, San Jose, Calif., "Power System Computer Feasibility Study," for the Department of Public Service of the State of New York, December, 1968.

18. R. H. Hayward, "Reliability Predictions Assessment of Failure Rate Leads to System Security," Elec. Times, Vol. 154, No. 5, 1968, pp. 149-153.

19. H. Glavitsch, "Aspects of a Central Network Monitoring System," Brown Boveri Review, Vol. 55, No. 7, 1968, pp. 359-364.

20. "Dr. Louis T. Rader Urges Utility Management to Utmost Automation," Electrical World, Vol. 170, No. 19, 1968, pg. 34.

21. Y. Ohba and Y. Sekine, "Security Control of Power System Cascade - Shutdown Due to Supply-Demand Unbalance," Electrical Engineering in Japan, Vol. 88, No. 9, 1968, pp. 60-70.

22. E. C. Scottz and P. W. Cash, "Security of supply in the planning and operation of European power systems - Part 1 and Part 2, IEEE Winter Power Meeting, New York, NY, Jan. 28-Feb. 2, 1968.

23. M. M. Adibi et. al., "Power system computer feasibility study," IBM, San Jose, Calif., 1969.

24. P. W. Ash, et. al., "Reliability of Supply in European Power System Projects and Operation," Bull. Assoc. Suisse Elect., Vol. 60, No. 12, pp. 549-558, 1969. (In French)

25. G. A. Davidson, et. al., "Short-Time Thermal Ratings for Bare Overhead Conductors," IEEE Trans. on Power App. and Sys., Vol. PAS-88, No. 3, March 1969, pp. 194-199.

26. H. Dommel, "New Applications of Digital Computers in Network Calculations," Enegie, 121, No. 6, pp. 206-215, 1969. (In German)

27. S. Hayashi, "Power System Security Assessing by Digital Computer Simulation - Basis Control," PICA Conference, Denver, Colorado, May 18-21, 1969.

28. F. L. Goss, "Evaluation of Coordination in the United States Electric Power Industry," American Power Conference Preprints, 1969.

29. W. S. Ku and P. VanOlinda, "Security and Voltage Applications of the Public Service Dispatch Computer," PICA Conference, Denver, Colorado, May 18-21, 1969, pp. 201-207.

30. H. D. Limmer, "Techniques and Applications of Security Calculations Applied to Dispatching Computers," presented at the Third Power Systems Computation Conference, Rome, Italy, June 23-27, 1969.

31. G. D. Rockefeller, "Fault Detection with a Digital Computer," IEEE Trans. Power App. and Sys., Vol. PAS-88, No. 4, April 1969, pp. 438-464.

32. T. E. DyLiacco, "The Emerging Concept of Security Control," Proc. 1970 Symp. Power Syst., Purdue Univ., Lafayette, Indiana, May 1970.

33. D. L. Ewart, "Computer Technology Improves System Security," Transmission, Vol. 2, No. 1, pp. 13-16, 1970.

34. D. N. Ewart, "Automation Technology Aids Electric Utility System Security," CIGRE 32-10, 1970.

35. L. P. Hajdu, D. W. Bree, and A. W. Brooks, "On-line Monitoring of Power Systems Security," Paper 70CP690-PWR, IEEE 1970 Summer Power Meeting, Los Angeles, Calif.

36. G. W. Stagg, J. F. Dopazo, O. A. Klitin and L. S. VanSlyck, "Techniques for the Real-Time Monitoring of Power System Operations," IEEE Trans. on P.A.S. Vol. PAS-89, April 1970, pp. 545-555.

37. H. Ungrad, et. al., "Centrally Coordinated Back-up Protection and System Security Monitoring as Constituents of an Integrated System for the Automation of Power Transmission," CIGRE, 34-03, 1970.

38. "On-line Stability Analysis Study," North American Rockwell Information Systems Company, Anaheim, Calif., Report for Edison Electric Institute, Oct. 1970.

39. Electric Research Council, "Improved Operational and Control Methods for Bulk Power System Security," EEI Research Project RP90, Final Summary Report, February 1971.

40. IBM Research Division, San Jose, Calif., "Bulk Power Security Assessment," prepared for Edison Electric Institute, Research Project RP90-3, November 1970.

41. Final Report, EEI Project RP90-6, "Methods of Bulk Power System Security Assessment (Prob. Approach)" prepared by Electric Power Institute, Texas A&M University, College Station, Texas.

42. IEEE System Instrumentation Task Force, "Application of Instrumentation for the Evaluation of Power System Dynamic Performance," IEEE Paper 71 TP 579-PWR.

43. J. F. Aldrich, "Computer Directed Power System Control at the New York Power Pool," Joint Aut. Cont. Conf., 1971, pp. 10-11.

44. A. H. El-Abiad, "New Directions in Power Systems Reliability and Security," Proc. 3rd Syst. Theory Symp., Atlanta, 1971.

45. A. H. El-Abiad, "Power System Reliability Trends in the Seventies," Int. Conf. Syst. Comp. Mexico, Vol. 1, pp. 226-230, 1971.

46. G. England, et. al., "Security of Supply in the Design and Operation of the Grid System in England and Wales," WPC paper 245, Vol. 15, pp. 263-289.

47. D. N. Ewart, et. al., "Automation and Utility System Security," IEEE Spectrum, Vol. 8, No. 7, 1971, pp. 37-42.

48. W. F. Tinney and N. M. Peterson, "Steady-State Security Monitoring," Symposium Real-Time Control of Electric Power Systems," Brown, Boveri & Co., Ltd. Baden, Switzerland, September 27-28, 1971.

49. "Control Strategies for Power Systems," Summary Report of Engineering Foundation Conf., held in South Berwick, Maine, July 23-28, 1972.

50. T. E. DyLiacco, B. F. Wirtz, and D. A. Wheeler, "Automation of the CEI System for Security," IEEE Trans. on Power Apparatus and Sys., Vol. PAS-91, pp. 831-843, May/June 1972.

51. E. Handschin, "Real-Time Control of Electric Power Systems," Elsevier, Amsterdam, 1972.

52. A. J. Korsak, "On the Question of Uniqueness of Stable Load-Flow Solutions," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 1093-1100, May/June 1972.

53. S. Narita and M. Hammam "Multicomputer control of voltage and reactive power in large-scale power pools," in Proc. 4th PSCC (Grenoble, France, 1972) Paper 2.3/1.

54. A. St. Johnston, "Data Processing and Computation for Real-Time Security Assessment," 4th PSCC Proc. Grenoble, France, 1972.

55. J. P. Bowles, et. al., "Performance Studies of Transmission Systems Involving the Integrated Operation of an Extensive Transmission Simulator Digital Computer and Analogue Computer," IEE Conf. Publ., No. 107, Nov. 1973, pp. 103-108.

56. A. S. Debs, "On-Line Control of Power Systems," paper presented at 1973 Georgia Tech Protective Relaying Conf., Atlanta, Georgia.

57. R. Foerst, "Methods for Dynamic Security Monitoring of Power Systems," (Translated by Bonneville Power Administration), ETZ-A Vol. 94, No. 4, 1973, pp. 216-220. (In German)

58. C. F. Panlus, "Keep Generators Running Improve Reliability at Little Cost," IEEE Trans. on Power App. and Sys., Vol. PAS-92, No. 1, 1973, pp. 243-247.

59. R. G. Rice and G. W. Stagg, "Application Program Design Criteria for the Southern Company Control System," PICA Conference Proceedings, 1973, pp. 128-134.

60. J. C. Russel and W. Rades, "The Wisconsin Electric Power Company Energy Control System," PICA Conference Proceedings, 1973, pp. 135-141.

61. "Electric Power Systems Analysis Research," report to National Science Foundation by Systems Control Inc., Palo Alto, Calif., July 1974.

62. M. M. Adibi, et. al., "The Utility of Load Flow for On-Line Security Assessment," paper presented at Winter Power Meeting, New York, Jan. 1974.

63. T. E. DyLiacco, "Real-Time Computer Control of Power Systems," IEEE Proc., (Special issue: Computers in the Power Industry), Vol. 62, No. 7, pp. 884-891, July 1974.

64. A. H. El-Abiad, "Advances in Power System Dynamics and Control," Iranian Journal of Science and Technology, No. 3, Vol. 3, July 1974.

65. A. V. Jain, et. al., "Reliability Cost in System Operation," paper C 74 314-1, presented at IEEE Winter Power Meeting, New York, 1974.

66. W. F. Tinney and M. Enns, (Editors), Computers In The Power Industry, Special Issue of IEEE Proc., July 1974.

67. J. M. Undrill, F. P. deMello, T. E. Kostyniak, and R. J. Mills, "Interactive Computation in Power System Analysis," IEEE Proc., (Special Issue: Computers in the power industry), July 1974.

68. "Economy-Security Functions in Power System Operations," prepared by IEEE Working Group on Operating Economics and presented at IEEE Winter Power Meeting, Jan. 1975 (IEEE Publ. 75 CH0969-5 PWR).

69. G. H. Couch and I. F. Morrison, "Computer Control in Substations: Allocation of Zones and Formulation of Switching Strategies for Primary and Back-Up Protection," IEEE Trans. on Power App. and Syst. Vol. PAS-94, No. 2, March/April, 1975, pp. 579-590.

70. P. L. Noferi and L. Paris, "Effects of Voltage and Reactive Power Constraints on Power System Reliability," IEEE Trans. on Power App. and Sys., Vol. PAS-94, No. 2, March/April 1975, pp. 482-490.

71. N. M. Peterson, et. al., "Advanced Applications System for the Wisconsin Electric Power Company Control Center," PICA Conf. Proc., New Orleans, June 1975.

72. F. K. Tseng, et. al., "Instrumentation and Control in EHV Substations," IEEE Trans. Power App. and Sys., Vol. PAS-94, No. 2, March/April 1975, pp. 632-641.

73. L. K. Kirchmayer, Economic Operation of Power Systems. New York: Wiley, 1958.

74. W. D. Stevenson, Jr., Elements of Power System Analysis. New York: McGraw-Hill, 1962.

75. G. W. Stagg and A. H. El-Abiad, Computer Methods in Power System Analysis. New York: McGraw-Hill, 1971.

76. O. I. Elgerd, Electrical Energy Systems Theory: An Introduction. New York: McGraw-Hill, 1971.

Data Base

A. State Estimation

77. F. C. Schweppe and J. Wildes, "Power System static state estimation, part I: Exact model," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 120-125, Jan. 1970.

78. F. C. Schweppe and D. B. Rom, "Power system static state estimation, part II: Approximate model," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 125-130, Jan. 1970.

79. F. C. Schweppe, "Power system static-state estimation, part III: Implementation," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 130-135, Jan. 1970.

80. R. E. Larson, W. F. Tinney, and J. Peschon, "State estimation in power systems, part I: Theory and Feasibility," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 345-352, Mar. 1970.

81. R. E. Larson, W. F. Tinney, L. P. Hajdu, and D. S. Piercy, "State estimation in power systems, part II: Implementation and applications," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 353-359, March 1970.

82. G. W. Stagg, J. F. Dopazo, O. A. Klitin, and L. S. VanSlyck, "Techniques for the real-time monitoring of power system operations," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 545-555, April 1970.

83. J. F. Dopazo, O. A. Klitin, G. W. Stagg, and L. S. VanSlyck, "State calculation of power systems from line flow measurements," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 1698-1708, Sept./Oct. 1970.

84. J. F. Dopazo, O. A. Klitin, and L. S. VanSlyck, "State calculation of power systems from line flow measurements, part II," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 145-151, Jan./Feb. 1972.

85. A. S. Debs and R. E. Larson, "A dynamic estimator for tracking the state of a power system," IEEE Trans. Power App. Syst., Vol. PAS-89m pp. 1670-1678, Sept./Oct. 1970.

86. A. S. Debs and W. H. Litzenberger, "Experimental evaluation of tracking state estimation," in Proc. 7th PICA Conf. (Boston, Mass., 1971).

87. A. S. Debs, R. E. Larson, and L. P. Hajdu, "On-line sequential state estimation for power systems," presented at 4th PSCC, Grenoble, France, 1972, Paper 3.3/7.

88. F. Ariatti, V. Castagnoli, L. Marzio, and P. Ricci, "Methods for electric power system state estimation: Comparative analysis of computing simulations based upon generalized load flow, tracking and least square methods," in Proc. 4th PSCC (Grenoble, France, 1972). Paper 3.3/10.

89. G. H. Couch, A. C. Sullivan, and J. A. Dembecki, "A State Estimator Oriented to a Semi-Isolated 5 GW Power System," paper C 74 346-3 presented at IEEE Summer Power Meeting, 1974.

90. H. L. Fuller and T. A. Hughes, "State Estimation for Power Systems with Mixed Measurements," paper C 74 363-8 presented at IEEE Summer Power Meeting, 1974.

91. S. L. Johnson, "An algorithm for state estimation in power systems," in Proc. 8th PICA Conf., (Minneapolis, Minn., June 1973), pp. 319-326.

92. R. D. Masiello and F. C. Schweppe, "A tracking static state estimator," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 1025-1033, Mar./April 1971.

93. O. J. M. Smith, "Power system state estimation," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 363-379, March 1970.

94. A. Z. Gamm, "Power system instantaneous state estimation as a problem in nonlinear programming," Electr. Technol. USSR, Vol. 3.

95. B. Poretta and R. S. Dhillon, "Performance evaluation of state estimation from line flow measurements on Ontario hydro power system," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 1702-1712, Sept/Oct. 1973.

96. K. A. Clements, et. al., "A multiarea approach to state estimation in power system networks," presented at IEEE Summer Power Meet., San Francisco, Calif. 1972, paper C72 465-3.

97. K. Uemura, "State estimation of large scale electric power systems by decomposition methods," in Proc. 5th IFAC World Congr. (Paris, France, 1972). Paper 3.3/6.

98. J. A. Bubenko and L. D. Petterson, "On-line State Estimation," paper C74 321-6, presented at IEEE Summer Power Meeting, 1974.

99. J. Svoen, S. A. Fismen, H. H. Faanes, and A. Johannessen, "The online closed-loop approach for control of generation and overall protection at Tokke power plants," presented at Int. Conf. Large High Tension Electric Systems, CIGRE, Paris, France, 1972. Paper 32-06.

100. P. Goeminne, P. Van Miegroet, and J. Waha, "Descarte project, a contribution to the improvement of security in transport networks," in Proc. 4th PSCC (Grenoble, France, 1972). Paper 3.3/9.

101. D. F. Koenig and J. P. O'Malley, "State estimation: An on-line luxury for the electric utilities industry?," presented at IEEE Summer Power Meet., San Francisco, Calif., 1972. Paper C72 463-8.

102. H. Kobayashi, S. Ninagawa, K. Tsujiyama, Y. Tamura, and S. Narita, "Dynamic state estimation techniques applied to security control problems" in Proc. 4th PSCC (Grenoble, France, 1972). Paper 3.3/2.

103. H. Glavitsch, "Economic load dispatching and corrective rescheduling using on-line information of the system state," in Proc. 8th PICA Conf. (Minneapolis, Minn., June 1973), pp. 412-420.

104. E. Handschin, "Theorie and Anwendung von Estimationsmethoden fur die on-line Ueberwachung and Fuhrung electrischer Energiesysteme," Habilitationsschrift, Eidgenossische Tech. Hochsch., Zurich, Switzerland, 1973.

105. K. Srinivasan and Y. Rogichaud, "A dynamic estimator for complex bus voltage determination," IEEE Trans., Vol. PAS-93, No. 5, Sept./Oct. 1975.

106. F. Aschmoneit, "Zeit- und Speicherbedarf der exakten on-line Lastflussberechnung," Elektrotech. Z. Ausg. A, Vol. 94, no. 8, pp. 499-500, 1973.

107. E. Handschin and F. D. Galiana, "Hierarchial state estimation for real-time monitoring of electric power systems," in Proc. 8th PICA Conf. (Minneapolis, Minn., June 1973), pp. 304-312.

108. K. Reichert, E. Handschin, J. Caneel, and H. Asal, "On-line Lastflussberechnung (state estimation) in electrischen Energieveisorgungssystemen, Grundlagen," Elektrotech. Z. Ausg. A, 1973.

109. K. Reichert, J. Cancel, H. Asal, and E. Handschin "Die Ueberwachung eines Teils des Schweizerischen Hochspannungsnetzes mit State-Estimation, Prozessaufbau and praktische Erfahrungen," SEV-Bulletin (Special Issue), Zurich, Switzerland, 1973.

110. F. Ariatti, "Answers to questionnaire on on-line power system state estimation," Document of CIGRE Study Committee 32, Working Group 01, 1973.

111. E. Handschin, "Real-time data processing using state estimation in electric power systems," in Real Time Control of Electric Power Systems. Amsterdam, The Netherlands: Elsevier, 1972, ch. 2.

112. A. S. Debs, "Data Base for Real-Time Power System Control," invited paper to Allerton Conference on Circuits and Systems held in Montecello, Illinois (Oct. 1973).

113. K. Srinivasan, et. al., "A Dynamic Estimator for Complex Bus Voltage Determination," IEEE Trans. on Power Apparatus and Systems, Vol. 93, No. 5, pp. 1581-1588, 1974.

114. H. Asal, et. al., "State Estimation for Power System Monitoring in a Section of the Swiss EHV System - System Configuration and Operating Experience," CIGRE preprint 32-11, 1974.

B. Detection and Identification of Excessively Noisy Data

115. H. M. Merrill and F. C. Schweppe, "Bad data suppression in power system static state estimation," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 2718-2725, Nov./Dec. 1971.

116. E. Handschin, F. C. Schweppe, J. Kohlas, and A. Fiechter, "Bad data analysis for power system state estimation," IEEE Trans., PAS-94, No. 2, March/April 1975.

117. J. F. Dopazo, O. A. Klitin, and A. M. Sasson, "State Estimation for Power Systems: Detection and Identification of Gross Measurement Errors," in Proc. 8th PICA Conf. (Minneapolis, Minn., June 1973), pp. 313-318.

118. J. Kohlas, "On Bad Data Suppression in Estimation," IEEE Trans. Automat. Contr. (Tech. Notes and Corresp.), Vol. AC-17, pp. 827-828, Dec. 1972.

119. E. Handschin and J. Kohlas, "On Statistical Data Processing For Power System Operation," in Proc. 4th PSCC (Grenoble, France, 1972). Paper 3.3/5.

C. Modeling Problems and Sensitivity Analysis

120. H. D. Merrill and F. C. Schweppe, "On-Line System Model Error Correction," IEEE Winter Power Meeting 1973, C73-106-2.

121. T. Stuart and C. J. Herget, "Sensitivity Analysis of Weighted Least Squares State Estimation For Power Systems," IEEE Trans. on Power App. and Syst., Vol. PAS-92, No. 5, Sept./Oct. 1973.

122. M. Allam, et. al., "A General Algorithm for Estimating Power System Variables and Network Parameters," paper presented at Summer Power Meeting, paper C74 331-5, Anaheim, Calif., July 1974.

123. K. A. Clements, et. al., "The Effects of Measurement Non-Simulatansity, Bias, and Parameter Uncertainty on Power System State Estimation," 1973 PICA Conference Proceedings, June 1973.

124. A. S. Debs, "Estimation of Steady-State Power System Model Parameters," IEEE Trans. on Power App. and Syst., Vol. PAS-93, No. 5, Sept./Oct. 1974.

125. A. S. Debs, and W. H. Litzenberger, "The BPA State Estimator Project: Tuning of the Network Model," to be presented at IEEE Summer Power Meeting, July 1975.

126. K. A. Clements and R. J. Ringlee, "Treatment of Parameter Uncertainty in Power System State Estimation," Paper C-74-311-7 presented at Summer Power Meeting held in Anaheim, Calif., July 1974.

D. Configurations of Networks and/or Measurement Systems

127. A. M. Sasson, S. T. Ehrmann, P. Lynch, and L. S. VanSlyck, "Automatic Power System Network Topology Determination," IEEE Trans. Power App. Syst. Vol. PAS-92, pp. 610-618, Mar./Apr. 1973.

128. T. DyLiacco, K. Mamarao, and A. Weiner, "Network Status Analysis For Real Time Systems," in Proc. 8th PICA Conf. (Minneapolis, Minn., June 1973).

129. F. Ariatti, "Selection of Telemetered Quantities for On-Line Supervision and Control of an Electric Power System with the Aid of a Real-Time Computer," presented at Operational Research Symp. (Varna, Bulgaria, May 1970).

130. G. H. Couch, and I. F. Morrison, "Data Validation and Topology Determination for Power System Monitoring and Control," paper C74 361-2, presented at IEEE Summer Power Meeting, Anaheim, Calif., July 1974.

E. General and Related Works

131. F. C. Schweppe and E. Handschin, "Static State Estimation in Power Systems," IEEE Proceedings, Vol. 62, No. 7 (Special Issue: Computers in the Power Industry), July 1974.

132. J. F. Dopazo, S. T. Ehrmann, O. A. Klitin, and A. M. Sasson, "Justification of AEP Real Time Load Flow Project," IEEE Trans. Power App. Syst. Vol. PAS-92, pp. 1501-1509, Sept./Oct. 1973.

133. L. S. VanSlyck and J. F. Dopazo, "Conventional Load Flow Not Suited For Real Time Power System Monitoring," in Proc. 8th PICA Conf. (Minneapolis, Minn., 1973), pp. 369-376.

134. T. DeVille and F. C. Schweppe, "On Line Identification of Interconnected Network Equivalents From Operating Data," presented at IEEE Summer Power Meeting, San Francisco, Calif., 1972. Paper C72 464-6.

135. F. C. Schweppe, "Role of System Identification in Electric Systems," paper presented at Power Systems Computation Conference held in Grenoble, France, Sept. 1972.

136. A. S. Debs, "Estimation of External Network Equivalents From Internal System Data," IEEE Trans., Vol. PAS-94, No. 2, March/April 1975.

137. A. S. Debs, "Parameter Estimation for Power Systems in the Steady-State," IEEE Trans., Vol. AC-19, No. 6, (Special Issue on System Identification and Time Series Analysis), Dec. 1974.

138. J. Toyoda, "An Application of State Estimation to Short Term Load Forecasting, Part I: Forecasting Modeling," IEEE Trans. on Power App. and Syst., Vol. PAS-89, No. 7, 1970, pp. 1678-1682.

139. J. Toyoda, "An Application of State Estimation to Short Term Load Forecasting, Part II: Implementation," IEEE Trans. Power App. and Syst. Vol. PAS-89, No. 7, 1970, pp. 1683-1688.

140. D. P. Lijesen, et. al., "Forecasting of Hourly Loads to Improve Operating Decisions in Power Systems," paper presented at IEEE Winter Power Meeting, 1971.

141. R. N. Allan, et. al., "Probabilistic Analysis of Power Flows," Proc. IEE, Vol. 121, 1974, pp. 1551-1556.

142. B. Borkowska, "Probabilistic Load Flow," IEEE Trans. App. and Syst., Vol. PAS-93, No. 3, May/June 1974, pp. 752-759.

143. R. A. Pyne, "Short-Term Bus Load Forecasting and Its Intended Use in Scheduled Outage Analysis," Proc. 1974 IEEE Conference on Decision and Control, pp. 593-598, Nov. 1974.

144. J. F. Dopazo, O. A. Klitin and A. M. Sasson, "Stochastic Load Flows," IEEE Trans. on Power App. and Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 299-309.

145. W. R. Christiaanse, "Short-Term Load Forecasting Using General Exponential Smoothing," paper 70 TP 681-PWR, presented at IEEE Summer Power Meeting, July 1970.

146. W. L. Miller, et. al., "Dynamic State Estimation in Power Systems," IEEE Trans. on Aut. Cont., Vol. 16, No. 6, 1971, pp. 841-846.

147. C. Dechamps, "Procedure for the Treatment and Analysis of the Data Necessary for Simulating System Operation," CIGRE preprint 1972, 32-09.

148. F. D. Galiana, et. al., "Combined Network and Power Station Dynamic State Estimation," 4th PSCC Proc., Grenoble, France, 1972.

149. H. Kobayashi, et. al., "Dynamic State Estimation Techniques Applied to Security Control Problems," 4th PSCC Proc., Grenoble, France, 1972.

150. R. Walters, "State Estimation as a Data Validation Technique in Power System Monitoring," IEE Conf. Publ., No. 103, pp. 163-167, 1973.

151. F. D. Galiana, "An Application of System Identification and State Prediction to Electric Load Modeling and Forecasting," MIT, Cambridge, Mass., Electric Power Systems Engineering Laboratory, Report No. 28, March, 1971.

152. K. A. Clements and B. F. Wollenberg, "An Algorithm for Observability Determination in Power System State Estimation," paper A75 447-3, presented at IEEE Summer Power Meeting, July 1975.

153. H. P. Horisberger, et. al., "A Fast Decoupled Static State-Estimator for Electric Power System," paper F75 428-3, presented at IEEE Summer Meeting, July 1975.

154. G. T. Heydt, "Stochastic Power Flow Calculations," paper A75 530-6, presented at IEEE Summer Power Meeting, July 1975.

Steady-State Security Analysis

A. Contingency Evaluation and Load Flow Analysis

155. E. Hines and H. Limmer, "Rapid Load Flow Program using super-position," Proc. Power Systems Computation Conference 1, Queen Mary College, London, England, 1963.

156. O. T. Geraskin, "Topological Analysis of Current Distribution Factors in Power Networks," Izvestiya vuz Energetika, No. 5, 1967, pp. 20-28.

157. W. F. Tinney and J. W. Walker, "Direct Solutions of Sparse Network Equations by Optimally Ordered Triangular Factorization," Proc. IEEE, Vo. 55, pp. 1801-1809, Nov. 1967.

158. G. L. Brewer and C. C. Tam, "The Computational Aspects of the CEGB New National Control Centre," Proc. of 3rd Power System Computation Conf., Vol. 2, June 1969.

159. H. E. Brown, "Contingencies Evaluated by a Z-Matrix Method," IEEE Trans. Power App. Syst., Vol. PAS-88, pp. 409-412, April 1969.

160. M. L. Boughmann and F. C. Schweppe, "Contingency Evaluation: Real Power Flows From a Linear Model," IEEE Summer Power Meeting, Los Angeles, Calif., July 12-17, 1970.

161. T. H. Brinkworth, "Single Contingency Engineering A Key to Maximum Reliability," T and D, Vol. 22, No. 10, 1970, pp. 80-85.

162. G. W. Stagg and A. G. Phadke, "Real Time Evaluation of Power System Contingencies--Detection of Steady-State Overloads," presented at IEEE Summer Power Meeting, July 1970.

163. S. T. Despotovic, B. S. Babic, and V. P. Mastilovic, "A Rapid and Reliable Method for Solving Load Flow Problems," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 123-130, Jan./Feb. 1971.

164. K. Uemura, "Power Flow Solution by a Z-matrix type method and its application to contingency evaluation," presented at IEEE PICA Conf., Boston, 1971.

165. K. Uemura, "Load Flow Calculations by Perturbed Netwon Method," Elec. Eng. Jap., Vol. 91, No. 5, 1971, pp. 82-88.

166. N. M. Peterson, W. F. Tinney, and D. W. Bree, Jr. "Iterative linear ac power flow solution for fast approximate outage studies," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 2048-2056, Sept./ Oct. 1972.

167. B. Stott, "Decoupled Newton Load Flow," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 1955-1959, Sept./Oct. 1972.

168. K. Uyemura and J. Matsuki, "A Method of Load-Flow Calculations for Security Control in Power Systems." Electrical Engineering in Japan, Vol. 92, No. 3, 1972.

169. D. A. Conner, "Representative Bibliography on Load-Flow Analysis and Related Topics," A paper presented at the IEEE PAS Winter Meeting, New York, January 28-February 2, 1973.

170. A. Findlay, et. al., "On Line Security Monitoring for Large Power Systems," Ph.D. Thesis, University of Toronto, Mech. Eng., 1973.

171. W. E. Bosarge, J. A. Jordan, and W. A. Murray, "A non-linear block SOR-Newton Load Flow Algorithm," presented at IEEE PES Summer Meet., Vancouver, July 15-20, 1973. Paper C73 644-5.

172. M. S. Sachdev and S. A. Ibrahim, "A Fast Approximate Technique for Outage Studies in Power System Planning and Operation," presented at IEEE PES Summer Meet., Vancouver, July 15-20, 1973. Paper T 73 469-4.

173. B. Stott and O. Alsac, "Fast Decoupled Load Flow," presented at IEEE PES Summer Meet., Vancouver, July 15-20, 1973, Paper T 73 463-7. Also IEEE Trans. Power App. Syst., Vol. PAS-93, pp. 859-869, May/June 1974.

174. H. H. Happ, "Diakoptics--The solution of system problems by tearing," IEEE Proc., (Special Issue: Computers in the Power Industry), July 1974.

175. H. E. Brown, Solution of Large Networks by Matrix Methods, Wiley Interscience Publ., New York, 1975.

176. J. Medanic and B. Avramovic, "ε-Coupling Method for the Solution of Load Flow Problems in Power Systems," to be published in Proc. IEE.

B. Interchange Capacity Calculations

177. G. L. Landgren, H. L. Terhune, and R. K. Angel, "Transmission Interchange Capability-Analysis by Computer," Paper No. 71-CP-608-PWR, IEEE Summer Power Meeting, Portland, Oregon, 1971.

178. H. E. Brown, "Simultaneous Interchange Optimization by Means of the Z-Matrix," in Porc. 8th PICA Conf., (Minneapolis, Minn., 1973), pp. 250-254.

179. G. T. Heydt and W. M. Grady, "A Z-Matrix Method for Fast Three Phase Load Flow Calculations," Power Industry Computer Applications Conference, Minneapolis, Minn., June 1973.

180. G. L. Landgren and S. W. Anderson, "Simultaneous Power Interchange Capability Analysis," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 1973-1986, Nov./Dec. 1973.

181. M. K. Jain, et. al., "Improved Area Interchange Method for Use with Any Numerical Technique," Paper T 74 014-7, presented at IEEE Winter Power Meeting, Jan. 1974.

182. G. T. Heydt and B. M. Katz, "A Stochastic Model in Simultaneous Interchange Capacity Calculations," IEEE Trans. on Power App. and Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 350-359.

C. Steady-State Equivalents

183. J. B. Ward, "Equivalent Circuits for Power-Flow Studies," AIEE Transactions, Vol. 68, pp. 373-382, 1949.

184. H. Duran and N. V. Arvanitidis, "Simplifications for Area Security Analysis--A New Look At Equivalence," IEEE Trans. on P.A.S., Vol. PAS-91, March/April 1972, pp. 670-678.

185. S. Vemuri, E. F. Hill and R. Balasubramanian, "A Note on Static Equivalent Circuits of Power Systems," A paper presented at the IEEE PES Winter Meeting, New York, Jan. 28-Feb. 2, 1973.

186. W. F. Tinney, et. al., "Sparsity Oriented Network Reduction," Proc. 1973 PICA Conf., pp. 384-390, June 1973.

187. E. K. Paulsson, "Network Equivalents for On-Line Systems," Paper C 74 373-7, presented at IEEE Summer Power Meeting, July 1974.

188. A. S. Debs, "Estimation of External Network Equivalents from Internal System Data," IEEE Trans. on Power App. and Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 273-279.

D. Steady-State Operating Limitations

189. Aluminum Overhead Conductor Enginnering Data, Aluminum Company of America.

190. R. J. C. Wood, "Heating of Large Steel-Cored Aluminum Conductors," AIEE Trans., Vol. 43, pp. 1258-1262, Oct. 1974.

191. S. Butterworth and E. E. Hutchings, "Caracteristiques Electrique et Regimes Thermiques des Lignes Electrique Aeriennes," 13th CIGRE Conf., Paris, France, June 29-July 8, 1950, Report No. 204.

192. C. Jean-Richard, "Thermal Protection of Transformers," CIGRE, 1950, paper no. 309.

193. H. E. House and P. D. Tuttle, "Current-Carrying Capacity of ACSR," AIEE Trans., (Power App. and Syst.), Vol. 77, pp. 1169-1177, Feb. 1959.

194. G. A. Davidson, et. al., "Short-Time Thermal Ratings for Bare Overhead Conductors," IEEE Trans. on Power App. and Syst., Vol. PAS-88, No. 3, March 1969, pp. 194-199.

Transient and Dynamic Security Analysis

A. General Works on Transient Stability/Security

195. E. W. Kimbark, "Power System Stability," John Wiley & Sons, Inc., New York 1945.

196. C. Concordia, "Performance of Interconnected Systems following Disturbances," IEEE Spectrum, June 1965.

197. IEEE Committee Rep., "Computer Representation of Excitation Systems," IEEE Trans. Power App. Syst. Vol. PAS-87, pp. 1460-1464, June 1968.

198. "On-Line Stability Analysis Study," RP90-1, Report for Edison Electric Institute by the North American Rockwell Information Systems Company, October 12, 1970.

199. IEEE Committee Report, "System Load Dynamics--Simulation Effects and Determination of Load Constants," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 600-609, Mar./Apr. 1973.

200. V. R. Sastry and P. G. Murthy, "Derivation of Completely Controllable and Completely Observable State Models for Multimachine Power System Stability Studies," Int. J. Control, 1972, Vol. 16, No. 4, pp. 777-788.

201. K. N. Stanton, "Dynamic Energy Balance Studies For Simulation of Power-Frequency Transients," IEEE Trans. on Power Apparatus and Systems, Vol. PAS-91, pp. 110-117, 1972.

202. C. J. Tavora and O. J. M. Smith, "Characterization of Equilibrium and Stability in Power Systems," IEEE Trans. Power Apparatus and Systems, Vol. PAS-91, No. 3, May/June 1972, pp. 1127-1130.

203. IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines in Power Systems Studies," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 1904-1915, Nov./Dec. 1973.

204. V. A. Venikov, "Estimation of Electrical Power System Steady State Stability in Load Flow Calculations," paper T 74 320-8 presented at IEEE Summer Power Meeting, Anaheim, Calif., July 1974.

205. D. Crevier and F. C. Schweppe, "The Use of Laplace Transformers in the Simulation of Power System Frequency Transients," IEEE Trans. on Power App. and Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 236-241.

206. M. Furuyama and J. L. Kirtley, Jr., "Transient Stability of Superconducting Alternators," IEEE Trans. on Power App. and Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 320-328.

207. "Symposium on Adequacy and Philosophy of Modeling: Dynamic System Performance," prepared by IEEE Working Group on Dynamic System Performance, Report 75 CH0970-4-PWR, presented at IEEE Winter Power Meeting, Jan., 1975.

B. Numerical Methods

208. W. D. Humpage and B. Stott, "Predictor-corrector Methods of Numerical Integration in Digital-Computer Analyses of Power System Transient Stability," Proc. Inst. Elec. Eng., Vol. 112, 1965.

209. K. N. Stanton and S. N. Talukdar, "New Integration Algorithms for Transient Stability Studies," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 985-991, May/June 1970.

210. S. N. Talukdar, "Iterative multistep methods for Transient Stability Studies,"IEEE Trans. Power App. syst., Vol.PAS-90,Jan/Feb 1971, pp.96-102.

211. H. W. Dommel and N. Sato, "Fast Transient Stability Solutions," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 1643-1650, July/Aug. 1972.

212. W. Janischewskyj and P. Kundur, "Simulation of the non-linear Dynamic Response of Interconnected Synchronous Machine, Part I: Machine Modeling and Machine-Network Interconnection Equations," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 2064-2069, Sept./Oct. 1972.

213. P. L. Dandeno and P. Kundur, "Simulation of the Non-Linear Dynamic Response of Interconnected Synchronous Machines, Part II--Network Solution Procedures and Comparisons of Particular Computational Methods," ibid., Vol. PAS-91, pp. 2069-2077, Sept./Oct. 1972.

214. P. L. Dandeno and P. Kundur, "A Non-Iterative Transient Stability Program Including the Effects of Variable Load-Voltage Characteristics," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 1478-1484, Sept./Oct. 1973.

215. G. Steinbrenner and D. P. Grelopdos, "An Algorithm for Transient and Dynamic Simulation Study," in 1973 PICA Conf. Rec., pp. 113-117.

216. H. W. Dommel and N. Sato, "Fast Transient Stability Solutions," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 1643-1650, July/Aug. 1972.

217. H. L. Fuller, P. M. Hirsch, and M. B. Lambie, "Variable Integration Step Transient Analysis," in 1973 PICA Conf. Rec., pp. 156-161.

218. M. M. Adibi, et. al., "Solution Methods for Transient and Dynamic Stability," Proc. IEEE, (Special Issue: Computers in the Power Industry) July 1974.

C. Hybrid/Analog Computation

219. P. C. Krause, T. A. Lipo, and D. P. Carroll, "Applications of Analog and Hybrid Computation in Electric Power System Analysis," IEEE Proc., July 1974.

220. "Long-Term System Dynamics Hybrid Computation," Final Report to Electric Power Research Institute by University of Missouri-Columbia, Project EPRI RP908-1, April 1975.

D. Lyapunov's Method

221. A. H. El-Abiad and K. Nagappan, "Transient Stability Regions of Multimachine Power Systems," IEEE Trans. Power App. Syst., Vol. PAS-85, pp. 169-179, February 1966.

222. G. E. Gless, "The Direct Method of Lyapunov Applied to Transient Power System Stability," IEEE Trans. Power App. Syst., Vol. PAS-85, pp. 159-168, February 1966.

223. Y. N. Yu and K. Vongasuriya, "Nonlinear Power System Stability Study by Lyapunov Function and Zubov's Method," IEEE Trans. Power App. Syst., Vol. PAS-86, pp. 1480-1485, December 1967.

224. N. DharmaRao, "Generation of Lyapunov Functions for the Transient Stability Problem," Trans. of the Engineering Institute of Canada, EIC-68-Elec. 3, Vol. 11, No. C-3, May 1968, pp. 1-8.

225. M. A. Pai et. al, "Power System Transient Stability Regions Using Popov's Method," IEEE Trans. Power App. Syst., Vol. 89, No. 5/6, pp. 788-795, May/June 1970.

226. J. L. Willems and J. C. Willems, "The Application of Lyapunov Methods to the Computation of Transient Stability Regions for Multimachine Power Systems," IEEE Trans. Power App. Syst., Vol. PAS-89, No. 5/6, pp. 795-801, May/June 1970.

227. M. R. Pavella, "Transient Stability of Multi-Machine Power Systems by Lyapunov's Direct Method," presented at IEEE Winter Power Meeting, New York, January 1971.

228. M. R. Pavella, "Critical Survey of Transient Stability Studies of Multimachine Power Systems by Lyapunov's Direct Method," Proceeding of the 9th Annual Allerton Conference on Circuits and System Theory, Oct. 1971, pp. 751-767.

229. A. K. DeSarkar and N. D. Rao, "Zubov Method and Transient Stability Problems of Power Systems," IEEE Proceedings, Vol. 118, No. 8, pp. 1035-1040, August 1971.

230. J. L. Willems, "Direct Methods for Transient Stability Studies in Power System Analysis," IEEE Trans., Vol. AC-16, No. 4, August 1971, pp. 332-341.

231. A. Calvaer, J. L. Horward and M. Ribbens-Pavella "On the Definition of a Stability Index in Power Systems," Revue El. (Belgium), Vol. 7, No. 4, 1972, pp. 85-87. In English.

232. M. Mansour, "Stability Analysis and Control of Power Systems," Proceedings of the Symposium on Real-Time Control of Electric Power Systems, 1971 (Real-Time Control of Electric Power Systems, Elsevier, 1972).

233. H. F. Williams, S. A. Louie and G. W. Bills, "Feasibility of Lyapunov's Functions for the Stability Analysis of Electric Power Systems Having up to 60 Generators," IEEE Trans., Vol. PAS-91, No. 3, May/June 1972, pp. 1145-1157.

234. F. S. Prabhakara and A. H. El-Abiad, "A Simplified Determination of Transient Stability Regions for Lyapunov Method's," IEEE Trans. Power App. and Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 672-689.

E. Long-Term Dynamic Response

235. C. Concordia, F. P. deMello, L. K. Kirchmeyer, R. P. Schulz, "Prime Mover Response and System Dynamic Performance," American Power Conference, 1966, Vol. 28, pp. 1074-1085, Spectrum, Oct. 1966, pp. 106-111.

236. D. N. Ewart, F. P. deMello, "FACE-A Digital Dynamic Analysis Program," IEEE Conference Record 39C69; 1967, PICA, pp. 83-94.

237. K. N. Stanton, "Dynamic Energy Balance Studies for Simulation of Power-Frequency Transient," Proc. 1971 IEEE PICA Conference, pp. 173-181.

238. "Long-Term Power System Dynamics," Final Report by General Electric Company to Electric Power Research Institute, Project EPRI 90-7-0, June 1974.

239. V. Converti, et. al., "Long-Term Stability Solution of Interconnected Power Systems," paper F75 444-0, presented at IEEE Summer Power Meeting, July 1975.

F. Dynamic Equivalents

240. W. T. Brown, W. J. Cloues, "Combination Load Flow and Stability Equivalents for Power System Representation on A.C. Analyzers," AIEE Trans. Vol. 74, Part 3, 1955, pp. 782-786.

241. "Computer Representation of Excitation Systems," IEEE Committee Report, IEEE Trans. PAS-87, No. 6, June, 1968.

242. H. E. Brown, R. B. Shipley, D. Coleman, and R. E. Nied, Jr., "A Study of Stability Equivalents," IEEE Trans. Power App. Syst., Vol. PAS-88, pp. 200-207, March 1969.

243. A. Chang and M. M. Adibi, "Power System Dynamic Equivalents," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 1737-1744, Nov./Dec. 1970.

244. General Electric Company, "Power System Equivalents," prepared for Edison Electric Institute, Research Project RP90-3, November 1970.

245. H. E. Brown, "A New Y-Matrix Algorithm for Transient Stability," Presented at IEEE Summer Power Meeting, Portland, Oregon, 1967.

246. R. L. Hauth, R. P. Schulz, "Effects of Synchronous Machine Modeling in Large-Scale System Studies," Final Report for Northeast Power Coordinating Council (NPCC) Task Force on System Studies, System Dynamic Techniques Working Group, December 1, 1971.

247. A. Kuppurajula, S. Elangovan, "Simplified Power System Models for Dynamic Stability Studies," IEEE Trans., Vol. PAS-90, Jan./Feb. 1971, pp. 11-23.

248. W. A. Mittlestadt, "Reduced Dynamic Equivalents for Transient Stability Studies," Internal Memorandum, Bonneville Power Administration, Portland, Oregon, November, 1971.

249. A. Rahimi, et. al., "Dynamic Aggregation and the Calculation of Transient Stability Indices," Proc. 1971 PICA Conf., Boston, Mass.

250. J. M. Undrill, J. A. Casazza, E. M. Gulachenski, and L. K. Kirchmayer, "Electromechanical Equivalents for Use in Power System Stability Studies," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 2060-2071, Sept./Oct. 1971.

251. J. M. Undrill and A. E. Turner, "Construction of Power System Electromechanical Equivalents by Model Analysis," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 2049-2059, Sept./Oct. 1971.

252. F. Saccomano, "Development and Evaluation of Simplified Dynamical Models for Multi-Machine Electric Power Systems," Proc. 4th PSCC, Grenoble France, 1972, paper n. 3.1.22.

253. M. L. Chan, R. D. Dunlop, F. C. Schweppe, "Dynamic Equivalents for Average System Frequency Behavior Following Major Disturbances," IEEE Trans., Vol. PAS-91, No. 4, July/Aug., 1972, pg. 1637.

254. S. T-Y. Lee, "Transient Stability Equivalents for Power System Planning," Electric Power Systems Engineering Laboratory, Report 38, Massachusetts Institute of Technology, June, 1972.

255. K. N. Stanton, "Power System Dynamic Simulation Using Models with Reduced Dimensionality," Proc. JACC, August 16-18, 1972, pp. 415-419.

256. Woodard, J. B., Jr., "Power System Model Reduction--A Canonical Representation," Electric Power Systems Laboratory Report No. 35, MIT, Cambridge, Mass., February, 1972.

257. S. T-Y. Lee and F. C. Schweppe, "Distance Measures and Coherency Recognition for Transient Stability Equivalents," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 1550-1557, Sept./Oct. 1973.

258. J. E. VanNess, M. Zimmer, M. Cultu, "Reduction of Dynamic Models of Power Systems," Proc. 1973 PICA Conf., Minneapolis, Minnesota, 1973, pp. 105-112.

259. "Coherency Based Dynamic Equivalents for Transient Stability Studies," Final Report prepared for Electric Power Research Institute, by Systems Control, Inc., Project EPRI 904, Jan. 1975.

260. R. W. deMello, R. Podmore, and K. N. Stanton, "Coherency-Based Dynamic Equivalents: Applications in Transient Stability Studies," Proc. PICA Conf., June 1975.

261. W. W. Price, et. al., "Dynamic Equivalents from On-Line Measurements," paper T75 080-7 presented at IEEE Winter Power Meeting, Jan. 1975.

Measures of Security

A. Security Indices

262. W. G. Tuel and A. G. Dewey, "Power System Security Indices," PICA 1971, Conference Proceedings, pp. 365-373.

263. Reference Number 40 above.

264. "Application of Security Indices and Restraints to a Real Power System," IBM. Phase A Interim Report to Electric Power Research Institute, RP90-3, Phase II, Feb. 1974.

B. Probabilistic Security Measures

265. A. D. Patton, "Short Term Reliability Calculation," IEEE Trans. Power App. Syst., Vol. PAS-89, pp. 509-513, April 1970.

266. R. Billinton, Power System Reliability Evaluation. New York: Gordon and Breach, 1970.

267. R. Billinton, "Bibliography on the Application of Probability Methods in Power System Reliability Evaluation," IEEE Trans. on Power App. Syst., Vol. PAS-91, No. 2, 1972, pp. 649-660.

268. A. D. Patton, "A Probability Method for Bulk Power Security Assessment, I--Basic Concepts," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 54-61, Jan./Feb. 1972.

269. A. D. Patton, "A Probability Method For Bulk Power System Security Assessment, II--Development of Probability Models for Normally-Operating Components," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 2480-2485, Nov./Dec. 1972.

270. A. D. Patton, "A Probability Method for Bulk Power System Security Assessment, III--Models for Stand-by Generators and field data Collection and Analysis," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 2486-2493, Nov./Dec. 1972.

271. R. Billinton, R. J. Ringlee and A. J. Wood, "Power System Reliability Calculations," The MIT Press, 1973.

272. A. D. Patton, "Assessment of the Security of Operating Electric Power Systems Using Probability Methods," IEEE Proc. (Special Issue: Computers in the Power Industry), Vol. 62, No. 7, pp. 892-901, July 1974.

273. R. C. Wilson, et. al., "The Intermediate-Term Security Assessment of a Power Generating System" paper T75 106-0, presented at IEEE Winter Power Meeting, New York, 1975.

274. C. K. Pang and A. J. Wood, "Multi-Area Generation System Reliability Calculations," IEEE Trans. on Power App. Syst., Vol. PAS-94, No. 2, March/April 1975, pp. 508-517.

C. Cost of Insecurity

275. "Cost of Supply Interruption to the Consumer," Electrical Review, Vol. 181, No. 15, Oct. 13, 1967, pp. 533-534.

276. "CEGB's Cost Studies for Security," Electrical Review, Vol. 181, No. 16, Oct. 20, 1967, pp. 569-570.

277. R. Bruce Shipley, A. D. Patton, J. S. Denison, "Power Reliability Cost vs. Worth," IEEE Winter Power Meeting, New York, Jan. 30-Feb. 4, 1972.

D. Interactive Security Evaluation

278. Bruce F. Wollenberg, "The Operator Oriented Load Flow and Security Dispatch," PICA Conference, Denver, Colorado, May 18-21, 1969, pp. 192-200.

279. R. N. Adams and M. A. Laughton: "An On-Line Interactive Load Flow Program as an Aid to Power System Development and Operation," 6th Universities Power Engineering Conference, UMIST, Manchester, England, Jan. 1971.

280. F. Schlaepfer, T. C. Kelly and A. G. Dewey, "An Interactive Load Flow Program," IEEE Trans. on P.A.S., Vol. PAS-91, Jan./Feb. 1972, pp. 78-84.

281. John M. Undrill, F. Paul DeMello, Theodore E. Kostyniak, and Richard J. Mills, "Interactive Computation in Power System Analysis," IEEE Proceedings, Vol. 62, No. 7, July 1974, pp. 1009-1018.

282. T. E. DyLiacco, and D. L. Rosa, "Designing an Effective Man-Machine Interface for Power System Control," Proc. 1975 PICA Conf., June 1975.

Pattern Recognition

283. "Bulk Power Security Assessment," IBM Research Division, San Jose, California, Final Technical Report for Edison Electric Institute, November 1970.

284. "On-Line Stability Analysis Study," North American Rockwell Information Systems Company, Anaheim, Calif., Report for Edison Electric Institute, October 1970.

285. W. G. Tuel, Jr., "A Pattern Recognition Approach to Power System Security," Interim Report for Edison Electric atory, San Jose, Calif., 1970.

286. C. K. Pang, "Security Assessment in Power Systems," Proceedings of the Midwest Power Symposium, University of Michigan, Ann Arbor, Michigan, Oct., 21-22, 1971.

287. C. K. Pang, "Studies on Security Evaluation by Pattern Recognition and Unit Commitment by Dynamic Programming in Power System," Ph.D. Thesis, Purdue University, Lafayette, In., 1972.

288. C. K. Pang, F. S. Prabhakara, A. H. El-Abiad, and A. J. Koivo, "Security Evaluation in Power Systems Using Pattern Recognition," IEEE Trans. Power App. and Sys., Vol. PAS-93, No. 3, pp. 969-976, May/June 1974.

289. L. A. Beattie, "Experience with Power System Security Analysis via Pattern Recognition Techniques," paper A75 449-9, presented at IEEE Summer Power Meeting, July, 1975.

290. K. S. Fu, and J. M. Mendel, Adaptive Learning and Pattern Recognition Systems, Academic Press, 1970.

291. N. J. Nilsson, Learning Machines, McGraw-Hill, 1965.

292. K. S. Fu, Sequential Methods in Pattern Recognition and Machine Learning, Academic Press, 1968.

Security-Constrained Optimization

293. R. B. Shipley and M. Hochdorf, "Exact Economic Dispatch--Digital Computer Solution," AIEE Trans. Power App. Syst., Vol. PAS-75, pp. 1147-1153, Dec. 1956.

294. J. Carpentier, "Contribution to the Economic Dispatch Problem," Bull. Soc. Franc. Elect., Vol. 8, pg. 431, Aug. 1962.

295. J. F. Dopazo, O. A. Klitin, G. W. Stagg, and M. Watson, "An Optimization Technique for Real and Reactive Power Allocation," Proc. IEEE, Vol. 55, 1877-1885, Nov. 1967.

296. H. W. Dommel and W. F. Tinney, "Optimal Power Flow Solutions," IEEE Trans. Power App. Syst., Vol. PAS-87, pp. 1866-1876, Oct. 1968.

297. D. W. Wells, "Method for the Secure Loading of a Power System," Proc. Inst. Elec. Eng., Vol. 115, No. 8, pp. 1190-1194, Aug. 1968.

298. J. W. Dorney and M. S. Hammam, "Optimal Control of Multi-Area Power Systems," presented at IEEE PES Summer Meeting, Dallas, Texas, 1969. Paper 69 CP 656-PWR.

299. A. M. Sasson, "Nonlinear Programming Solutions for Load Flow, Minimum-Loss, and Economic Dispatching Problems," IEEE Trans. Power App. Syst., Vol. 88, pp. 399-409, April 1969.

300. A. M. Sasson, "Combined Use of the Powell and Fletcher-Powerll Nonlinear Programming Methods for Optimal Load Flows," IEEE Trans. Power App. Syst., Vol. PAS-88, pp. 1530-1537, Oct. 1969.

301. J. Peschon, et. al., "A Generalized Approach for Determining Optimal Solutions to Problems Involving System Security and Savings," System Control Inc., Palo Alto, Calif., Final Report for Edison Electric Institute, July 1970.

302. C. M. Shen and M. A. Laughton, "Power System Load Scheduling with Security Constraints Using Dual Linear Programming," Proc. Inst. Elec. Eng., Vol. 117, No. 11, pp. 2117-2127, Nov. 1970.

303. J. F. Aldrich, J. F. Leuer, and H. H. Happ, "Multi-area Dispatch," In Proc. 7th PICA Conf. (Boston, Mass., 1971), pp. 39-47.

304. S. W. Anderson, R. T. Jenkins, and D. S. Joy, "Short-Term Generation Schedule Optimization--A Dynamic Programming Approach," Presented at IEEE PES Summer Meeting, Portland, Oregon, 1971. Paper 71 CP 598-PWR.

305. N. V. Arvanitidis and J. Rosing, "The Use of Objective Functions in Real Power Dispatching," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 1742-1751, July/Aug. 1971.

306. M. R. Gent and J. W. Lamont, "Minimum-emission Dispatch," in Proc. 7th PICA (Boston, Mass., 1971), pp. 27-38.

307. R. B. Gungor, N. F. Tsang, and B. Webb, Jr., "A Technique for Optimizing Real and Reactive Power Schedules," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 1781-1790, July/Aug. 1971.

308. J. D. Guy, "Security Constrained Unit Commitment" IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 1385-1390, May/June 1971.

309. P. B. Henser and B. J. Cory, "Solution of the Minimum Loss and Economic Dispatch Problems Including Real and Imaginary Transformer Tap Ratio" in Proc. 7th PICA Conf. (Boston, Mass., 1971), pp. 228-233.

310. F. J. Jaimes, and A. H. El Abiad, "Optimization by a Sequence of Equality Constrained Problems--Its Application to Optimal Power Flows," in Proc. 7th PICA Conf. (Boston, Mass., 1971), pp. 219-227.

311. J. C. Kaltenbach and L. P. Hajdu, "Optimal Corrective Rescheduling for Power System Security," IEEE Trans. Power App. &. Syst., Vol. PAS-90, pp. 843-851, March/April 1971.

312. J. Peschon, D. W. Bree, and L. P. Hajdu, "Optimal Solutions Involving System Security," in Proc. 7th PICA Conf. (Boston, Mass., 1971), pp. 210-218.

313. W. O. Stadlin, "Economic Allocation of Regulating Margin," IEEE Power App. Syst., Vol. PAS-90, pp. 1776-1781, July/Aug. 1971.

314. T. Adielson, "Determination of an Optimal Power Flow by Iterative Suboptimizations," in Proc. 4th PSCC (Grenoble, France, 1972). Paper 2.1/9.

315. D. Arzamastev, P. Bartolomey, and A. Lipes, "Statistical Gradient Method and Accelerated Load Flow Calculation for Economic Load Scheduling," in Proc. 4th PSCC(Grenoble, France, 1972). Paper 2.1/7.

316. B. J. Cory and P. B. Henser, "Economic Dispatch with Security Using Non-Linear Programming," in Proc. 4th PSCC (Grenoble, France, 1972). Paper 2.1/5.

317. H. Daniels and M. S. Chen, "An Optimization Technique and Security Calculations for Dispatching Computers," IEEE Trans. on P.A.S., Vol. PAS-91, May/June 1972, pp. 883-888.

318. J. C. Dodu, P. Martin, A. Merlin, and J. Pouget, "An Optimal Formulation and Solution of Short-Range Operating Problems for a Power System with Flow Constraints," Proc. IEEE, Vol. 60, pp. 54-63, Jan. 1972.

319. C. H. Jolissaint, N. V. Arvanitidis, and D. G. Luenberger, "Decomposition of Real and Reactive Power Flows: A Method Suited for On-Line Applications," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 661-670, Mar./Apr. 1972.

320. O. P. Malik and A. S. A. Farag, "Optimization of Power System Reliability Under Cost Constraint," IEEE Winter Power Meeting, New York, Jan. 30-Feb. 4, 1972.

321. J. Peschon, H. W. Dommel, W. Powell , and D. W. Bree, Jr., "Optimum Power Flow for Systems with Area Interchange Controls," IEEE Trans. Power App. Syst., Vol. PAS-91, pp. 898-905, May/June 1972.

322. R. N. Mishra and V. R. Sastry, "Application of Memory Gradient Method to Economic Load Dispatching Problem," presented at IEEE PES Summer Meeting, San Francisco, Calif., 1972. Paper C72 438-0.

323. Y. Sekine and J. Kawakani, "Optimal Line Dispatching of Transmission Lines and Transformers," in Proc. 4th PSCC (Grenoble, France, 1972). Paper 2.1/3.

324. R. L. Sullivan, "Minimum Pollution Dispatching," presented at IEEE PES Summer Meeting, San Francisco, Calif., 1972. Paper C 72 468-7.

325. J. Velghe and N. Peterson, "Optimal Control of Real and Reactive Power Flow Under Constraints," in Proc. 4th PSCC (Grenoble, France, 1972), paper 2.1/4.

326. R. Billinton and S. S. Sachdeva, "Real and Reactive Power Optimization by Suboptimum Techniques," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 950-956, May/June 1973.

327. H. Duran, "A Simplex-Like Method for Solving the Optimum Power Flow Problem," in Proc. 8th PICA Conf. (Minneapolis, Minn., 1973), pp. 162-167.

328. J. W. Carpentier, "Differential Injections Method, A General Method for Secure and Optimal Load Flows," 1973 PICA Proc., paper TP VIII-E (a).

329. J. W. Carpentier, "Total Injections Method, A Method for the Solution of the Unit Commitment Problem Including Secure and Optimal Load Flow," 1973 PICA Proc., paper TP VIII-E(b).

330. O. J. Denison, N. D. Repper, and R. J. Ringlee, "Direction Economic Dispatch," presented at IEEE PES Winter Meeting, New York, 1973. Paper C 73-098.

331. J. W. Lamont and M. R. Gent, "Environmentally-Oriented Dispatching Technique," in Proc. 8th PICA Conf. (Minneapolis, Minn., 1973), pp. 421-427.

332. J. Gruhl, "Electric Power Unit Commitment Scheduling Using a Dynamically Evolving Mixed Integer Program," MIT Energy Lab., Rep. MIT-EL 73-007, Jan. 1973.

333. N. Nabona and L. L. Freris, "Optimization of Economic Dispatch Through Quadratic and Linear Programming," Proc. Inst. Elec. Eng., Vol. 120, pp. 574-579, May 1973.

334. H. Nicholson and M. J. H. Sterling, "Optimum Dispatch of Active and Reactive Generation by Quadratic Programming," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 644-654, Mar./April 1973.

335. G. F. Reid and L. Hasdorff, "Economic Dispatch Using Quadratic Programming," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 2015-2023, Nov./Dec. 1973.

336. A. M. Sasson, F. Viloria, and F. Aboytes, "Optimal Load Flow Solution Using the Hessian Matrix," IEEE Trans. Power App. Syst., Vol. PAS-92, pp. 31-41, Jan./Feb. 1973.

337. O. Alsac and B. Stott, "Optimal Load Flow with Steady-State Security," IEEE Trans. on Power App. Syst., Vol. PAS-93, No. 3, May/June 1974, pp. 745-751.

338. R. Podmore, "Economic Dispatch with Line Security Limits," IEEE Trans. Power App. Syst., Vol. PAS-93, pp. 289-295, Jan./Feb. 1974.

339. B. F. Wollenberg and W. O. Stadin, "A Real Time Optimizer for Security Dispatch," IEEE Trans. Power App. Syst., Vol. PAS-93, No. 5, Sept./Oct., 1974, pp. 1640-1649.

340. M. S. Sachdev and S. A. Ibrahim, "An Approach for Preventing System Insecurity Arising from Line and Transformer Outages," paper presented at IEEE Winter Power Meeting held in New York, Jan. 1975.

341. B. F. Wollenberg and K. A. Fegly, "A Cost Effective Security Dispatch Methodology," paper presented at IEEE Summer Power Meeting, held in San Francisco, July 1975, (paper F75 427-5).

342. M. A. Pai and S. R. Paranjothi, "Optimal Power Flow with Security Constraints Using Successive Linear Programming," paper A75 455-6, presented at IEEE Summer Power Meeting, July 1975.

Security Enhancement

343. L. P. Hajdu, R. Podmore, and D. W. Bree, "Security Enhancement for Power Systems," Final Report to Energy Research and Development Administration by Systems Control, Inc., Palo Alto, Calif., July 1975.

NATIONAL SCIENCE FOUNDATION Washington, D.C. 20550	SUMMARY OF COMPLETED PROJECT	Form Approved OMB No. 99R0013

Please read instructions on reverse carefully before completing this form.

1. INSTITUTION AND ADDRESS		2. NSF PROGRAM	3. GRANT PERIOD
Georgia Institute of Technology Atlanta, Georgia 30332		Engineering Division	from 10/1/74 to 9/30/76
4. GRANT NUMBER ENG74-17527	5. BUDGET DUR. (MOS) 24	6. PRINCIPAL INVESTIGATOR(S) A. S. Debs	7. GRANTEE ACCOUNT NUMBER E-21-645

8. SUMMARY (Attach list of publications to form)

Continuation of the effort under NSF Grant GK-37474 was undertaken in accordance with proposal on this matter. The primary effort consisted of two major tasks:

1. Development and testing of a state/parameter estimation program for on-line power system applications associated with steady-state models. Emphasis is placed on theory as well as computational efficiency.

2. Study of uncertainties associated with steady-state on-line power system security assessment. The main factor here is the accuracy of contingency evaluation which requires equivalent model representation of external systems.

Both of these tasks were successfully tackled. In the first task an efficient parameter estimation program using decoupling and sparsity techniques was developed and tested using actual power system data. This was reported in (1) and (2) below.

In case of the second task, an overall evaluation of external network equivalents was attempted. Portion of the methodology and results were reported in Ref. (3) below. The effort is culminating in a Ph. D. dissertation by Mr. Contaxis to be completed shortly. The primary result here is the development and testing, on a simulation basis, of a constrained quadratic optimization procedure which yields the best external equivalent using internal system data only.

Publications

(1) A. S. Debs and W. H. Litzenberger, "The BPA State Estimator Project: Tuning of the Network Model," paper presented at Summer Power Meeting, San Francisco, California, July, 1975.

(2) A. S. Debs and W. H. Litzenberger, "Implementation of the BPA On-Line State Estimator," paper presented at Power System Computation Conference, held in Cambridge, England in September 1975.

(3) G. Contaxis and A. S. Debs, "Network Equivalents for On-Line Power System Security Assessment," presented at IEEE Southeast Conference, held in Clemson, South Carolina, April 1976.

9. SIGNATURE OF PROJECT DIRECTOR	TYPED OR PRINTED NAME	DATE
	Atif S. Debs	10-15-76

NSF Form 98A (5-76)

FINAL REPORT

ESTIMATION OF MODEL PARAMETERS

FOR

POWER SYSTEM MONITORING AND CONTROL

by

A. S. Debs and G. Contaxis

NSF Grant No. ENG-7308204

October 1976

SUMMARY

The work performed under the present grant is an extension of the work under NSF Grant GK-37474. In the previous grant, the feasibility of using Kalman filtering algorithms for two types of power system parameter estimation problems was demonstrated. The first algorithm was designed to provide estimates of network admittances using simulated measurements of power flows, bus voltages, loads and generation levels. These measurements simulated a portion of the Bonneville Power Administration (BPA) data acquisition system. The second algorithm was designed to provide estimates of admittances of the external system equivalent network representation. Emphasis here was placed on information resulting from internal system switching operations or obtained in the scheduled or forced line additions or removals. The findings of this effort were reported in several publications (Ref. 4, 13, 33).

In extending these findings to more practical programs, the following factors became significant:

(a) Practical network sizes required the use of sparse matrix techniques. In this context, the Kalman filtering algorithms became less attractive since the parameter covariance matrix (or its inverse, the information matrix) became full after the second snapshot of the system.

(b) When dealing with raw measurement data, the presence of large measurement errors (so-called bad-data) could not be avoided. Furthermore, it was not clear if these errors were meter or modeling errors.

(c) The question of external system equivalent network identification was far from straightforward. In the first place, there was no assurance that the standard network reduction techniques used in system planning would be applicable in the case of system operation. Here the real world was being investigated where:

--nonlinear effects are pronounced,

--external system is constantly changing, and

--the large number of boundary buses can have a strong effect on system sparsity.

In response to factor (a) above, two approaches were adopted and implemented. In the first approach a suboptimal Kalman filtering scheme was adopted. In this scheme the sparsity of solution matrices was retained at the expense of some deterioration of performance. In the second approach, a maximum likelihood algorithm was developed. Here, the states are decoupled from the parameters in the information matrix. This resulted in a very attractive computational scheme which converged to the optimal solution. By decoupling the states from the parameters, state estimation per-se became decoupled from parameter estimation in every scan over all snapshots of the system. The implication here is that, this approach is quite attractive for on-line implementation.

Tests were conducted and reported (1) using the above two algorithms with raw data as input. It was concluded from these tests that significant modeling problems were present and that parameter estimation is a valuable tool to improve modeling accuracy. In addition, it pointed out the need for the detection and identification of bad data.

This brings us to factor (b) above. It was important, in this case, to distinguish between large meter and large parameter errors. As a result, a program was developed and tested for that purpose.

Finally, in regard to factor (c), a thorough investigation of steady-state network equivalencing procedures was conducted. New programs were developed which cope with the following problems:

--non-sparse network equivalent

--unknown external system

--unreported external system outages

Essentially, a least-squares optimization procedure is used here to obtain a simple and accurate network equivalent representation.

In terms of specific contributions of the research, we can cite the following.

--Demonstration of the feasibility and necessity of parameter estimation as it applies to on-line steady-state power system security assessment applications.

--Development of an efficient (storage and time-wise) program which can perform on-line state and parameter estimation using a real-time power system data base.

--Development of a program which can construct an external system equivalent from internal system data. This program has a detection subroutine for identifying unreported external system changes.

Based on those developments, BPA is proceeding with actual implementation of the state/parameter estimation program for use in its energy control center. As of this writing, we were unable to obtain actual data to test equivalencing program. This testing, however, will be conducted at BPA as soon as adequate data is available.

Aside from the final tests with the external equivalents program, we feel that all the objectives of our proposed research have been fulfilled. However, we do not feel that all the answers in this area have been obtained. Possible important questions that require answers are:

(a) Design of the data base (numbers and locations of measurements) to provide the best results in conjunction with a complete state/parameter estimation program.

(b) Development of alternative algorithms for state/parameter/bad-data detection which are competitive with the ones developed so far.

(c) Study of state/parameter estimation algorithms from a large-scale system point of view with emphasis on information structures and decentralized computation.

(d) Further investigations into the network equivalents problem. One possible investigation may consider a nonlinear external equivalent with higher levels of accuracy.

(e) Investigation of an inter-utility data base design whereby simplified external equivalents can be obtained in an on-line manner.

PARAMETER AND STATE ESTIMATION

1. INTRODUCTION

In this section we consider the accomplishments associated with Task 1 of our proposal to NSF. In this task the problem of developing and testing a state/parameter estimation program is attacked. Emphasis here is placed on sparse matrix methods and their impact on a particular solution methodology and vice versa. Once this is resolved, the problem of on-line implementation poses itself.

The main problem of on-line implementation relates to the theoretical modeling assumptions used in all the formulations of state estimation techniques. In one approach, the state estimator is tested with actual system data to see if it performs according to theoretical predictions. If it does, there is no modeling problem and the issue is resolved. This approach was not followed since apiori engineering judgement as well as previous studies (9) indicated that modeling problems exist to a certain extent. Hence, the approach that was followed consisted first, of studying the effect of modeling inaccuracy on state estimation performance, and second, of developing the computational tools to validate and tune the models in order to achieve acceptable performance.

As the problem of performance acceptability is resolved, the issue centers on the other aspects of on-line implementation. Two primary aspects are treated. The first is that of the overall role of state estimation in the control center. And the second is that of computational requirements.

The modeling problem with its implications is treated in Section 2. In Section 3, the techniques of parameter estimation used are developed mathematically and commented upon. Test results of a part of BPA's main-grid are presented and discussed in Section 4. And in Section 5, an integrated set of procedures for on-line implementation is developed and elaborated on. Conclusions and recommendations follow in Section 6.

2. THE MODELING PROBLEM

2.1 Sources and Extent of Modeling Inaccuracies

Two sets of model parameters are used in state estimation. The first set is that of admittances in the equivalent pi-section representation of transmission lines and transformers. The second set corresponds to the statistical parameters describing measurement and sensor errors.

Reasons for network parameter errors are several. Baumann[9] reports in a German study that standard formulas used to compute transmission line impedences contain errors to the extent of $\underset{\sim}{\sim}$5%. These can be due to truncation errors in the Taylor series expansion formulas. The exclusive use of positive-sequence impedences to represent untransposed lines and the neglect of mutual coupling between parallel lines can cause modeling problems. As for transformers, knowledge of the leakage impedences and its dependence on tap-settings is another problem. Certainly, aging, weather, and temperature effects are neglected. The end result is a network model with parameter errors of perhaps 10% in some bad cases.

In the case of the statistical parameters of measurement errors one is interested in reliable information on sensor and meter calibration curves. Since these are not always available, a thorough analysis of the sources of sensor errors is required. Internal studies at BPA have indicated that sensor errors are due primarily to two components. One is transducer bias and the other is potential and current transformer bias. The errors themselves are primarily bias errors in the sense that they do not change appreciably from one time instant to the next, or even over long periods of time.

An important problem here is to distinguish between the two types of modeling errors. They both reflect themselves as bias-type errors. In our efforts and formulations below the attempt has been and will be made to resolve this question.

2.2 Treatment of Modeling Problems

The approach taken in our work relies on a three-stage approach to the treatment of modeling problems.

Stage 1: Model Validity Assessment

The Chi-Square test provides the quickest means to see if the overall model is sufficiently accurate. Here one looks at the function

$$J = \frac{1}{M} \sum_{i=1}^{m} \frac{(z_i - h_i(\hat{x},p))^2}{\sigma_i^2} \tag{1}$$

where

$z_i \triangleq i^{th}$ measurement, $i=1,\ldots,m$

$\hat{x} \triangleq$ state-vector estimate, $\dim[\hat{x}]=n$

$p \triangleq$ parameter vector

$\sigma_i^2 \triangleq$ error variance of i^{th} measurement

and where

$$z_i = h_i(x,p)+v_i \tag{2}$$

with

$v_i \triangleq$ measurement error with zero mean and variance σ_i^2

and

$h_i(x,p) \triangleq$ nonlinear function relating the measured quantity z_i to the state vector x and parameter vector p.

The function J is chi-square distributed with m-n degrees of freedom. This implies that

$$E[J] = \frac{m-n}{m} < 1. \tag{3}$$

The test itself consists of computing the state estimate $\hat{x}$ and then evaluating J. If J is of the order of $\frac{m-n}{m}$ then the model is valid and state estimation is adequate. However, if $J \gg \frac{m-n}{m}$ then a modeling problem is present.

If a modeling problem is detected the next step is to attempt to pinpoint the source of the trouble. The simplest procedure is to examine the vector of residuals r whose i^{th} component is

$$r_i \triangleq \frac{(z_i - h_i(\hat{x},p))}{\sigma_i} \tag{4}$$

On the average, $|r_i| \leq 1$. Hence, if $|r_i| \gg 1$ then the parameters associated with $h_i(x,p)$ are in question. These could be parameters which appear in the function $h_i(x,p)$, as well as, parameters of measured quantities that are strongly coupled with z_i. From this one draws a candidate list of parameters that may be erroneous to a significant extent.

An alternative approach to identifying erroneous parameters is the one proposed in Ref. 14. However this approach is of the "bad-data suppression" type which is primarily geared to detect a single highly erroneous parameter.*

*Actually two or more erroneous parameters can be detected provided they are highly uncoupled.

Stage 2: Checking of Individual Components

In this stage careful analysis is undertaken to see if improvements in parameter values can be obtained. This is a stage of directly "measuring" individual parameters. The easiest parameters to check here are those of measurement errors. Suspected meters can be field-tested and calibrated in a rather routine manner. Next, one considers transformer parameters with special emphasis on leakage impedences, tap settings at both sides of the transformer and the effect of tap settings on leakage impedences. This can be best achieved through a careful evaluation of manufacturers design and test data. Direct tests on installed transformers cannot be ruled out especially when serious anomalies are still present in the model. As for transmission line data, the cases to watch for are those of parallel lines with mutual coupling. Otherwise, little can be done other than to check the accuracy of calculations provided in the data book.

Stage 3: Parameter Estimation

Parameter estimation provides the means to improve on the accuracy of the system models using masses of actual system data over representative operating conditions. It represents an important tuning process which ascertains the statistical validity of the models used over a wide range of operating conditions. In our assessment, this has the following advantages:

a. For on-line state estimation, the estimated and measured quantities will correspond closely to each other within the statistical accuracy of measuring instruments. This is essential to develop operator or dispatcher confidence in state estimation calculations and predictions.

b. Bad-data rejection and identification will become much easier to perform. As will be shown later, modeling errors can seriously degrade state estimator performance. This can cause the bad-data detection algorithm to be almost useless.

c. Improvements on some network models can be achieved. These can now be used in the applications or planning programs.

d. Once the software is developed, parameter estimation can become a routine function requiring only little man-hour effort and some computer time.

2.3 Sensitivity Analysis

Through sensitivity analysis one can determine those parameters which can cause serious errors in state estimation calculations. This can provide a further refinement over the results obtained in model validity assessments, thus limiting the set of parameters to be estimated.

Mathematical derivations of sensitivity analysis formulas showing sensitivity of state estimates to various sets of parameters are available in several references and will not be attempted here.[11] Instead, by means of a simple illustrative example, the contribution of parameter errors to the overall error in a given measurement is computed.

Denoting by Δp the expected error in the parameter vector one can write

$$\begin{aligned} z &= h(x, p+\Delta p)+v \\ &= h(x,p)+\left.\frac{\partial h}{\partial x}\right|_{x,p} \Delta p+v. \end{aligned} \tag{5}$$

The vector $\left.\frac{\partial h}{\partial x}\right|_{x,p}\Delta p$ represents a bias-type error which is added to metering error v. In the example chosen we consider a pi-section representation of a line or a transformer as shown in figure 1.

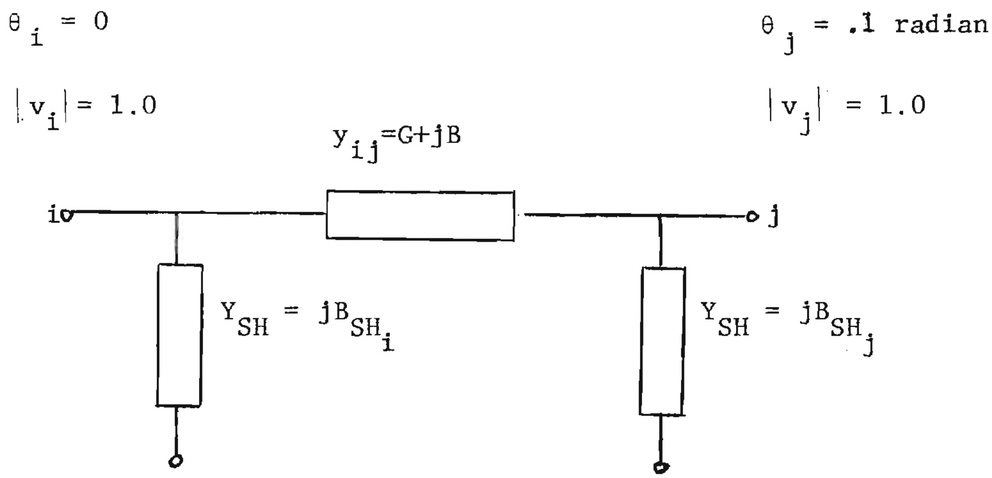


Fig. 1: Pi-Section Representation of a Typical Network Element

In the case of a transmission line, the following typical values are selected:

$$B = 100 \text{ pu}$$

$$G = 10 \text{ pu}$$

$$B_{SH_i} = B_{SH_j} = .01 \text{ pu.}$$

For the case where $\theta_j = .1r$ and parameter errors are 5% of nominal values one obtains:

$$\left|\frac{\partial T_{ij}}{\partial B} \Delta B\right| \cong .5 \text{ p.u.}$$

$$\left|\frac{\partial T_{ij}}{\partial G} \Delta G\right| \cong .25 \times 10^{-4} \text{ p.u.}$$

$$\left|\frac{\partial U_{ij}}{\partial B} \Delta B\right| \cong .25 \times 10^{-3} \text{ p.u.}$$

$$\left|\frac{\partial U_{ij}}{\partial G} \Delta G\right| \cong .5 \times 10^{-2} \text{ p.u.}$$

$$\left|\frac{\partial U_{ij}}{\partial B_{SH_i}} \Delta B_{SH_i}\right| \cong .5 \times 10^{-3}$$

where T_{ij} and U_{ij} are the real and reactive flows from bus i to bus j respectively.

In the case of a transformer the following values are selected:

B = 100 p.u.

G = 0.0

E = Tap Ratio = 1.0.

Assuming θ_j = .1r and 5% parameter errors one obtains:

$$\left|\frac{\partial T_{ij}}{\partial B} \Delta B\right| \cong .5 \text{ p.u.}$$

$$\left|\frac{\partial U_{ij}}{\partial B} \Delta B\right| \cong .25 \times 10^{-3} \text{p.u.}$$

$$\left|\frac{\partial U_{ij}}{\partial E} \Delta E\right| \cong 5 \text{p.u.}$$

The conclusions of the above results are

a. For transmission lines the sensitivity of real-flow to line susceptance errors is at least two orders of magnitude larger than the sensitivity to errors in all other parameters.

b. If the measurement error standard deviation has the reasonable value of .1 p.u., then the error due to line susceptance is five standard deviations which is quite unacceptable.

c. In the case of transformers, sensitivity to an error in tap positions is at least an order of magnitude larger than that with respect to leakage susceptance.

Therefore, the order of priority in estimating network parameters should be:

1. Tap settings of transformers
2. Line susceptance for transmission lines or leakage susceptance of transformers
3. (Possibly) line conductance of transmission lines.

All other parameter errors can be reasonably neglected.

The above results are consistent with findings in Ref.(11) and also with our own simulations as will be discussed later in the report. (For a detailed derivation of all sensitivity relations refer to Appendix A)

3. PARAMETER ESTIMATION

3.1 Problem Formulation

Denoting by z(k) the vector of measurements at time sample k, k=1,... N, one can write

$$z(k) = h(x(k),p) + v(k);\ k=1,\dots,N \tag{6}$$

where

$x(k) \triangleq$ state vector with dimension n

$p \triangleq$ parameter vector with dimension e

$v(k) \triangleq$ error in z(k) with zero mean and diagonal covariance matrix R(k).

Given value of the parameter vector is denoted by p^o. This can be related to the true (but unknown) parameter vector p by

$$p^o = p + w \tag{7}$$

where w represents the error in the knowledge of p and is modeled as a zero-mean random vector with diagonal covariance matrix M_o.

Denoting by $\hat{x}(k)$ and $\hat{p}$ the weighted least squares estimates of $x(k)$ and p, $k=1,\ldots,N$, then by definition $\hat{x}(k)$ and $\hat{p}$ should minimize

$$J = \sum_{k=1}^{N} [(z(k)-h(\hat{x}(k),\hat{p})^T R^{-1}(k)(z(k)-h(\hat{x}(k),\hat{p})] + (p^o-\hat{p})M^{-1}(p^o-\hat{p}). \tag{8}$$

3.2 Solution Methods

(a) Suboptimal Kalman Filter Approach

In this state and parameter estimates are updated with every new snap-shot measurement vector $z(k)$. Let $\hat{x}^n(n)$ and $\hat{p}^n$ be the estimates of $\hat{x}(n)$ and $\hat{p}$ at the minimum of

$$J_n = (p^o-\hat{p})M^{-1}(p^o-\hat{p}) + \sum_{i=1}^{n} (z(k)-h(\hat{x}(i),\hat{p})^T R^{-1}(i)(z(i)-h(\hat{x}(i),\hat{p})) \tag{9}$$

Also let M_n be the covariance of $\hat{p}^n$ then, it can be shown that $\hat{x}^{n+1}(n+1)$ and $\hat{p}^{n+1}$ will minimize.*

$$L_{n+1} = (\hat{p}^n-\hat{p}^{n+1})M_n^{-1}(\hat{p}-\hat{p}^{n+1})$$

$$+ (z(n+1)-h(\hat{x}^{n+1}(n+1),\ \hat{p}^{n+1})R^{-1}(n+1)(z(n+1)-$$

$$h(\hat{x}^{n+1}(n+1),\ \hat{p}^{n+1})). \tag{10}$$

Minimization of L_{n+1} w.r.t. $\hat{p}^{n+1}$ and $\hat{x}^{n+1}(n+1)$ can be accomplished via a Netwon-Raphson type algorithm. For simplicity let $\hat{p}_i$ and $\hat{x}_i$ represent the i^{th} iteration in computing $\hat{p}^{n+1}$ and $\hat{x}^{n+1}(n+1)$, then this algorithm is given by,

$$\begin{bmatrix} \hat{x}_{i+1} \\ \hat{p}_{i+1} \end{bmatrix} = \begin{bmatrix} \hat{x}_i \\ \hat{p}_i \end{bmatrix} + \Sigma_i \begin{bmatrix} H_i^T R^{-1}(z(n+1)-h(\hat{x}_i,\ \hat{p}_i)) \\ G_i^T R^{-1}(z(n+1)-h(\hat{x}_i,\ \hat{p}_i))+M^{-1}(\hat{p}^n-\hat{p}_i) \end{bmatrix} \tag{11}$$

where

$$\Sigma_i = \begin{bmatrix} (H_k^i)^T R^{-1} H_k^i & (H_k^i)^T R^{-1}(k) G_k^i \\ (G_k^i)^T R^{-1}(k) H_k^i & (G_k^i)^T R^{-1}(k) G_k^i + M_n^{-1} \end{bmatrix}^{-1}$$

*This is true using linearized equations only.

$$\triangleq \begin{bmatrix} \Sigma^i_{xx} & \Sigma^i_{xp} \\ \Sigma^i_{px} & \Sigma^i_{pp} \end{bmatrix}$$

$M_{n+1} \triangleq \Sigma^i_{pp}$

$\hat{x}_o \triangleq \hat{x}^n$

$\hat{p}_o \triangleq \hat{p}^n$

$i = 0,1,2,\ldots$

(b) Decoupled State Parameter Approach

Minimization of J as expressed in Eq. (8) requires that at the solution $\hat{x}(k)$ and $\hat{p}$ be zero i.e.

$$0 = \frac{\partial J}{\partial \hat{x}(k)} = -2H_k^T R^{-1}(k)(z(k)-h(\hat{x}(k),\hat{p}));\ k=1,\ldots,N, \tag{12}$$

$$0 = \frac{\partial J}{\partial \hat{p}} = -2\sum_{k=1}^{N}[G_k^T R^{-1}(k)(z(k)-h(\hat{x}(k),\hat{p}))]-2M^{-1}(p^o-\hat{p}) \tag{13}$$

where

$$\frac{\partial h}{\partial x}\Big|_{\hat{x}(k),\hat{p}} \quad \text{and} \quad G_k = \frac{\partial h}{\partial p}\Big|_{\hat{x}(k),\hat{p}}.$$

In the decoupled approach one preceeds according to the following steps:

<u>Step 1</u>: By holding $\hat{p}$ to be constant solve for $\hat{x}(k)$ using Eq. (9). This can be accomplished by means of the state estimation interative algorithm

$$\hat{x}^{i+1}(k) = \hat{x}^i(k) + [(H_k^i)^T R^{-1}(x)H_k^i]^{-1}(H_k^i)^T R^{-1}(z(k)-h(\hat{x}^i(k),\hat{p}) \tag{14}$$

where $i=1,2,\ldots,$ and

$$H_k^i = \frac{\partial h(x,p)}{\partial x}\Big|_{\hat{x}^i(k),\hat{p}}$$

<u>Step 2</u>: Hold $\hat{x}(k)$ at the values obtained in Step 1 and solve for

$\hat{p}$ iteratively according to Eq. (10) by means of the algorithm

$$\hat{p}^{i+1} = \hat{p}^{i} + (\sum_{k=1}^{N} [(G_k^i)^T R^{-1}(k) G_k^i] + M^{-1})^{-1} (M^{-1}(p^o - \hat{p}^i)$$

$$+ \sum_{k=1}^{N} (G_k^i)^T R^{-1}(k)(z(k) - h(\hat{x}(k), \hat{p}^i)) \qquad (15)$$

where

$$G_k^i = \frac{\partial h(x,p)}{\partial p}\Big|_{\hat{x}(k), \hat{p}^i} .$$

The summation terms in Eq.(12) are obtained sequentially during step 1. This implies that only one iteration can be used in Eq. (15).

<u>Step 3</u>: If $|\hat{p}^{i+1} - \hat{p}^i| \ll \epsilon$, where ϵ is a given positive constant, then the process is stopped. Otherwise, go back to Step 1 with the new parameter values.

If convergence occurs the necessary minimization conditions (12) and (13) are obviously satisfied. Due to the nonlinearity of the equations, there is no guarantee that the global minimum is attained. However, by calculating the chi-square performance index J given in the previous section, one can determine if a statistically acceptable solution has been obtained. In addition, engineering judgement as to the reasonableness of solutions can be exercised in order to make sure that adequate answers are obtained.

3.3 Parameter Estimation Programs

Two parameter estimation programs were developed during the summer of 1974 corresponding to the two approaches discussed above. With a few minor modifications the programs can be considered of the production type. Both programs are written for BPA's CDC-6400 computer using Fortran IV. In both cases sparsity techniques are employed to minimize the amount of computer core storage and to increase computational speeds.

The use of sparsity techniques poses no difficulties in the decoupled approach. However, for the recursive approach the matrix M_n and its inverse become full following the first snapshot. As a result an approximation is used whereby M_n is diagonalized at the end of every snapshot computation. This is the main reason the Kalman Filter approach is called suboptimal.

4. INITIAL TEST RESULTS

4.1 Introduction

During the summer of 1973 a limited number of computer simulations were conducted to study the issue of inaccurate modeling and the feasibility of parameter estimation. Results of this effort are provided in a technical paper.[4] In that paper two rather significant conclusions were obtained. First, inaccuracies in the network parameter models of the order of 5-10% can cause significant statistical degradation in state estimator performance. And second, these inaccuracies can be corrected for by means of parameter estimation leading to state estimator performance which is almost indistinguishable from that where a perfect model is used.

The above conclusions, however, were based on computer simulations and not on an actual system. Furthermore, parameter errors were introduced in a limited number of parameters. The limitation was mainly due to the fact that sparsity techniques were not implemented at that time. As soon as sparsity techniques were implemented in the summer of 1974, simulation tests were conducted whereby all network parameters contained a certain amount of error. Following that in November of 1974 data from eight remote stations of BPA's SCADA (Supervisory Control and Data Acquisition) system became available. This made it possible, for the first time, to test state estimation at BPA using adequate and reliable data. It is recalled here, that an earlier test in 1970 was made. However, at that time, SCADA was not in operation and many inadequacies in the data were present. Furthermore, parameter estimation programs were not available to improve on the network model.

In the following discussion, results of simulations as well as tests using actual system data are presented.

4.2 Simulation Results of Parameter Estimation Programs

The use of sparsity techniques in the parameter estimation programs permitted more realistic simulation tests whereby all network parameters were inaccurate to a certain degree. Here, a Gaussian random number generator was used to introduce errors in each parameter p_i, $i=1,\ldots\ell$. The error had a mean of zero and a standard deviation of $\alpha_i|p_i|$; where α_i ranged from 0.02 to 0.1 for a particular test case. For the results shown below $\alpha_i=0.05$ for all transmission line admittance terms and $\alpha_i=0.02$ for transformer tap ratios. The initial parameter covariance matrix M_o was diagonal with the i^{th} diagonal term given by:

$$(M_o)_{ii} = \alpha_i^2 |p_i|^2 .$$

The network chosen for simulations is the same one used in Ref. (4) It is representative of a portion of BPA's main grid network and associated data acquisition system.

In Figure (2), performance of the Kalman Filter algorithm is shown (dashed line). In the test simulated here, all transmission line parameters were randomly perturbed using a Gaussian random number generator. The errors had a mean of zero and a standard deviation of 5% of nominal value. As for transformers, a 2% random error was introduced in the tap ratios. For the first four time samples, no parameter estimation was attempted. These samples were used primarily to determine the set of parameters that should be estimated. The decision on which parameter to estimate was based on the analysis of residuals of line-flow measurements. Basically, if the residual of the real or reactive measurement became greater than 3 then the line susceptance and shunt capacitance are included in the candidate set. In the case of transformers, tap ratios were included automatically. The use of several time samples (in this case four of them) to decide on the candidate parameter set tended to make this set slightly larger than the case of basing the candidate list on one sample. The idea here is to exclude any parameters to which the performance index is insensitive and include as many parameters otherwise. This process normally did eliminate most of the radial portions of the network from consideration. And this is an expected result.

Starting with the fifth time sample, the parameter estimator was turned on. It is clear from Figure (2) that system performance immediately improves from values of the order 14-13 to values of the order of .6-.7. The improvement is attained at the first time sample parameter estimation is performed. However, this does not mean that the parameters become all accurate after one time sample. Parameter estimation at different operating conditions will continuously tend to improve the accuracy of parameter estimates.

Performance of the Decoupled State-Parameter algorithm is shown in Figure (3). The performance at the last time sample (10 samples were used) is plotted as a function of major loop iterations. Here all the line susceptances and shunt capacitances, as well as, transformer ratios were estimated. After four iterations, the performance changed from a value of 14.0 to 0.52. This performance is slightly better than that of the Kalman Filter approach.

4.3 Experimental Tests Using Actual Data

4.3.1 Experimental Setup

Data used for the reported results was collected on November 8, 1974.

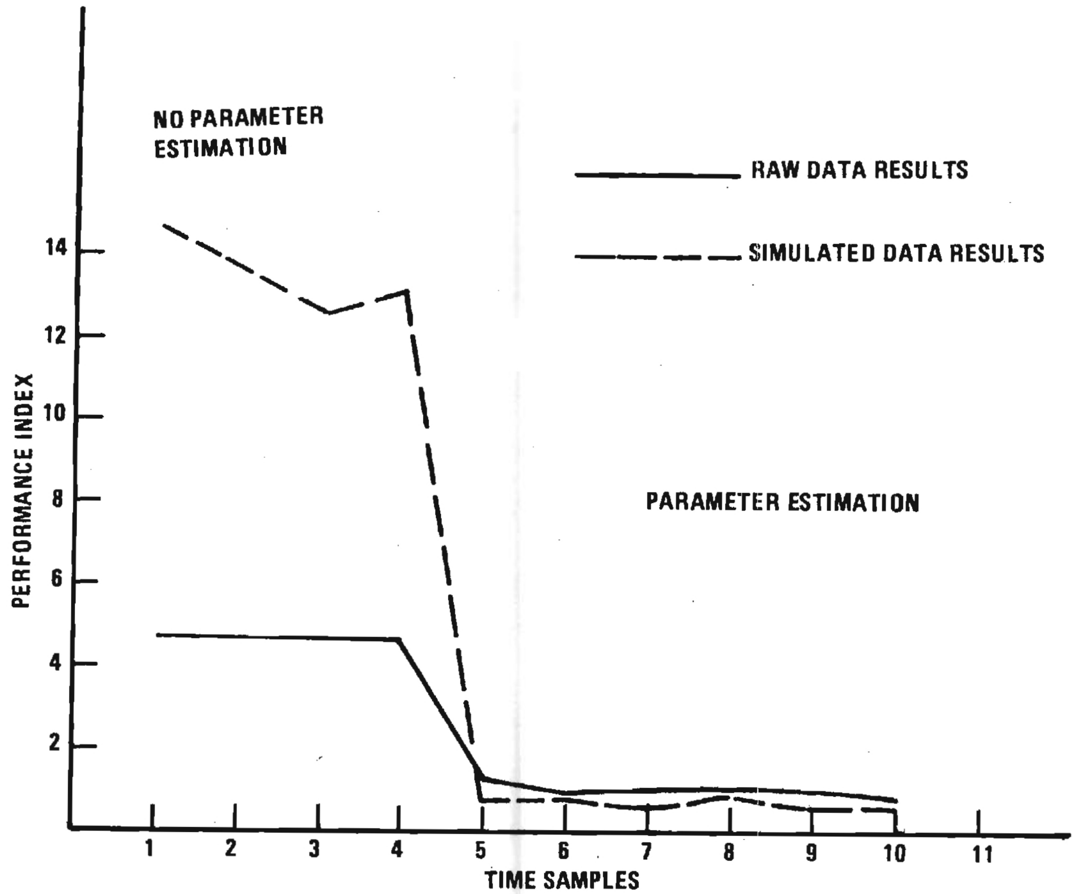


Fig. 2. Performance of Suboptimal Kalman Filter Algorithm Using Simulated as well as Actual Measurement Data

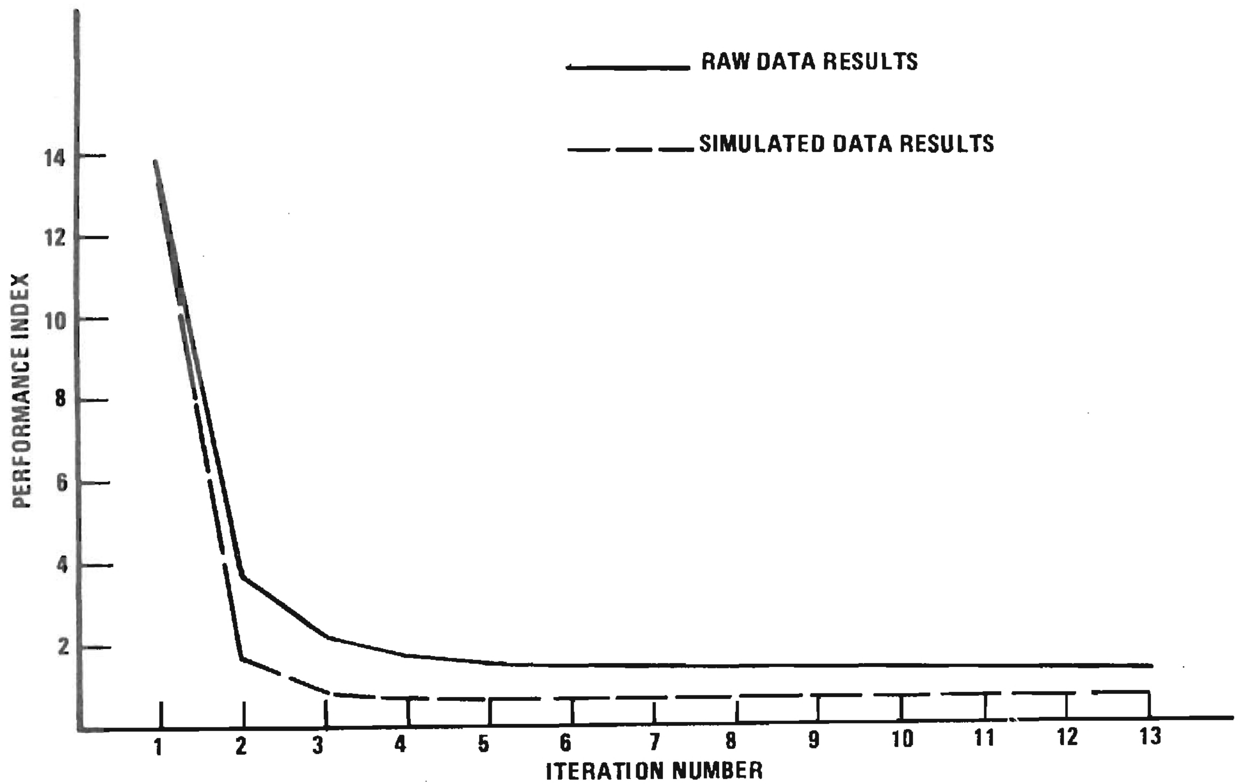


Fig. 3: Performance of the Decoupled State-Parameter Algorithm Using Simulated as well as Actual Measurement Data

It consisted of three 10 minute scans. Each scan consisted of 40 snapshots taken at 15 second intervals. One scan was conducted at noon time, the second at 7:00 p.m., and the third around midnight in order to observe the system at widely different operating conditions. It was readily noted that during each of the 10 minute periods the system operating conditions hardly changed. Hence, only five snapshots were retained for each of the three time periods.

At the time of conducting experimental tests, data from 8 remote stations became available. The network monitored by these stations is shown in Figure 4. It consists of 17 busses and 34 branches. 66 measurement quantities were transmitted every 15 seconds during a 10 minute interval upon request from the operator. Network status (or configuration) was determined directly from station diagrams displayed to the operator. In the actual on-line system, network configuration will be determined directly from status readings by SCADA I.

The 66 measurements mentioned consist of a mix of 12 voltage (KV), 21 real and 17 reactive line flow (MW and MVAR) measurements and 9 real and 7 reactive injection measurements. Transformer tap settings were also monitored. There are approximately twice as many measurements as there are state variables. This two-to-one redundancy is fairly evenly distributed over the entire system providing considerable back-up in cases of lost measurements due to various types of failures.

In testing the various components of SCADA I hardware very careful attention was given to the calibration of measurement instrumentation. From our point of view, it was crucial to know fairly accurately the expected errors in the various measurements. The BPA staff on their part, conducted independent tests to see if tranducers satisfy the required specifications under a variety of conditions. And after looking at calibration curves and internal memo's and talking to various individuals we became convinced that the formula

$$\sigma_z^2 = (.006z)^2 + (.005x(\text{full scale}))^2 \tag{16}$$

where z is a MW or MVAR measurement and σ_z^2 is the corresponding error variance, is quite adequate. For KV measurements the following formula was used:

$$\sigma_V = .005x(\text{full scale}). \tag{17}$$

From a sensitivity analysis point of view, the state estimates, where the model is exactly known, are quite insensitive to errors in the measurement covariance matrix. This is not true, however, when parameter estimation is attempted. A measurement covariance matrix with diagonal entries considerably smaller than corresponding true values will weigh the measurements too heavily causing significant model changes. Alternatively, variances which are greater than true values will tend to improve the model slightly causing no significant improvement in the state estimation process.

Preliminary checks on measurement accuracies were conducted prior to testing using the state and parameter estimation programs. One such check is shown in Table I whereby the injection measurement is subtracted from the sum of line flow measurements, around a given bus. The resulting error is compared with the cumulative σ defined by

$$\sigma = [\sigma_{INJ}^2 + \Sigma\,\sigma_{FLOW}^2]^{\frac{1}{2}}. \tag{18}$$

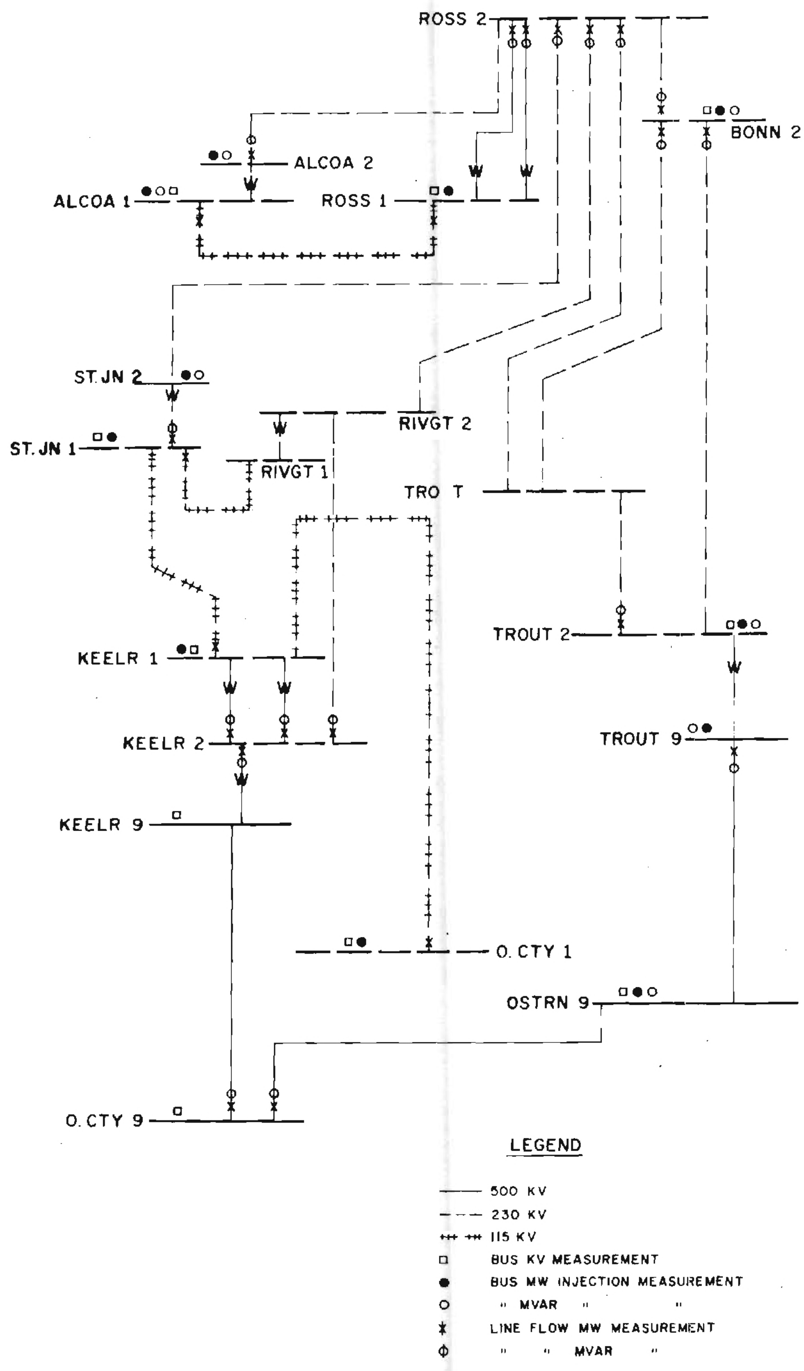


Fig. 4: Network Used in Experimental Tests

TABLE I: Preliminary Evaluation of Expected Errors in MW and MVAR Measurements

BUS	QUANTITY	ΣFLOW-INJ.	σ	ERROR
KEELR2	MW	4.6 MW	10.56	.434
BONN2	MW	11.3 MW	7.3	1.57
KEELR2	MVAR	3.32 MVAR	8.1	.40
OCTY1	MW	0.9	1.7	.53

It is clear from this table that our choice of σ values is reasonable. This method of checking did point out some inconsistencies. For example, we were able to determine that the reactive injection measurement at BONN2 needed recalibration. This measurement was not included for estimation purposes. It also pointed out errors in scale-factor conversion coefficients used to translate digital octal readings to MW, MVAR or KV quantities. It is, however, limited to those cases where all flows and injections are measured at a bus.

4.3.2 Comparison with Simulations

Figures (2) and (3) contain results of both parameter estimation approaches using actual as well as simulated data. In both cases parameter estimation significantly improves performance.

As will be discussed later, the experiments indicated that transformer data contained errors primarily in the series leakage susceptance as well as the tap setting at the fixed end. (The variable end was directly monitored.) Due to time limitations, only the decoupled algorithm was upgraded to perform the estimation of these parameters. The earlier version of the algorithm attempted the estimation of tap ratios only at transformer branches.

It is clear from Figure (3), that simulated and actual results correspond closely to one another. This confirms our earlier predictions

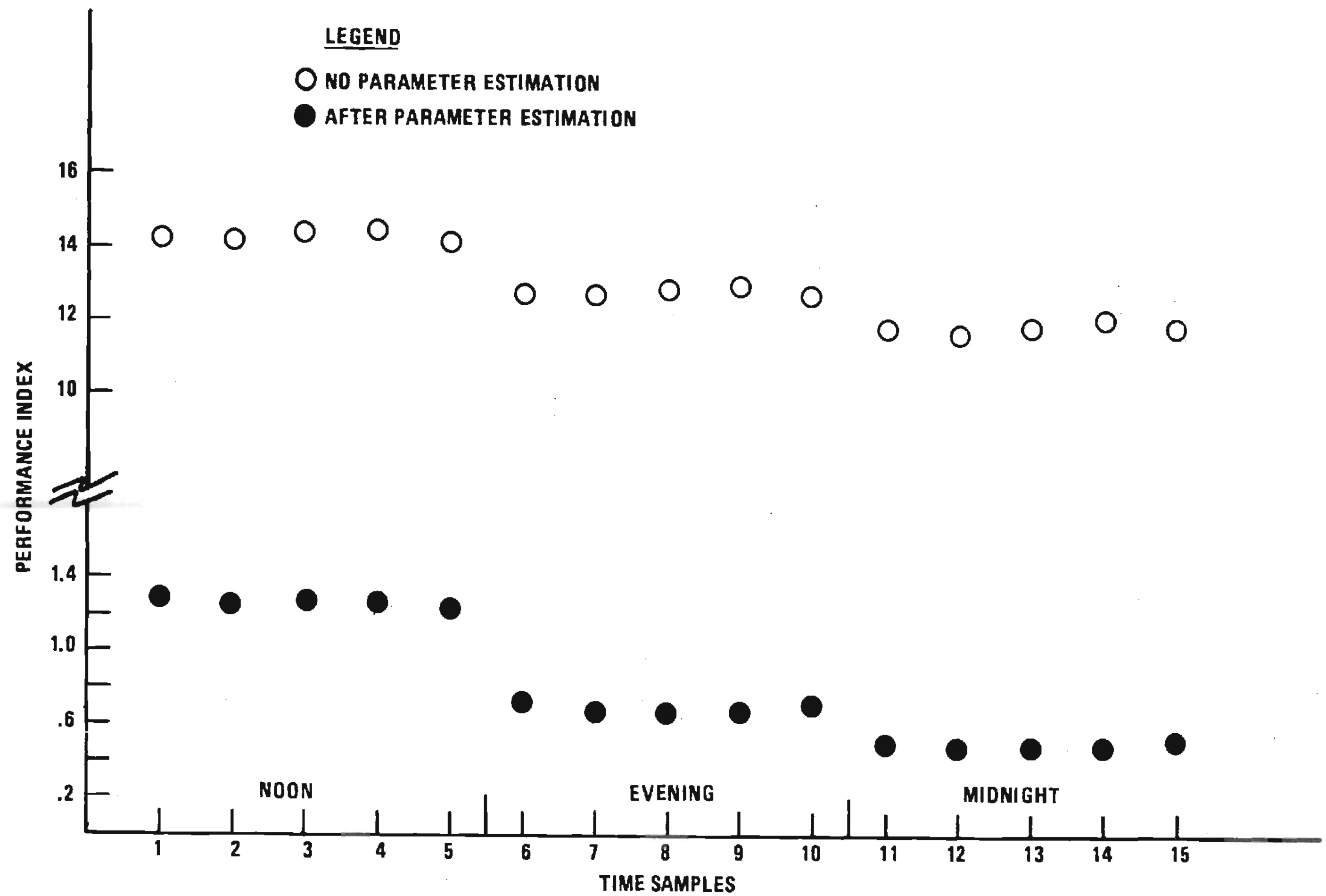


Fig. 5: Comparison of State Estimator Performance before and after Parameter Estimation

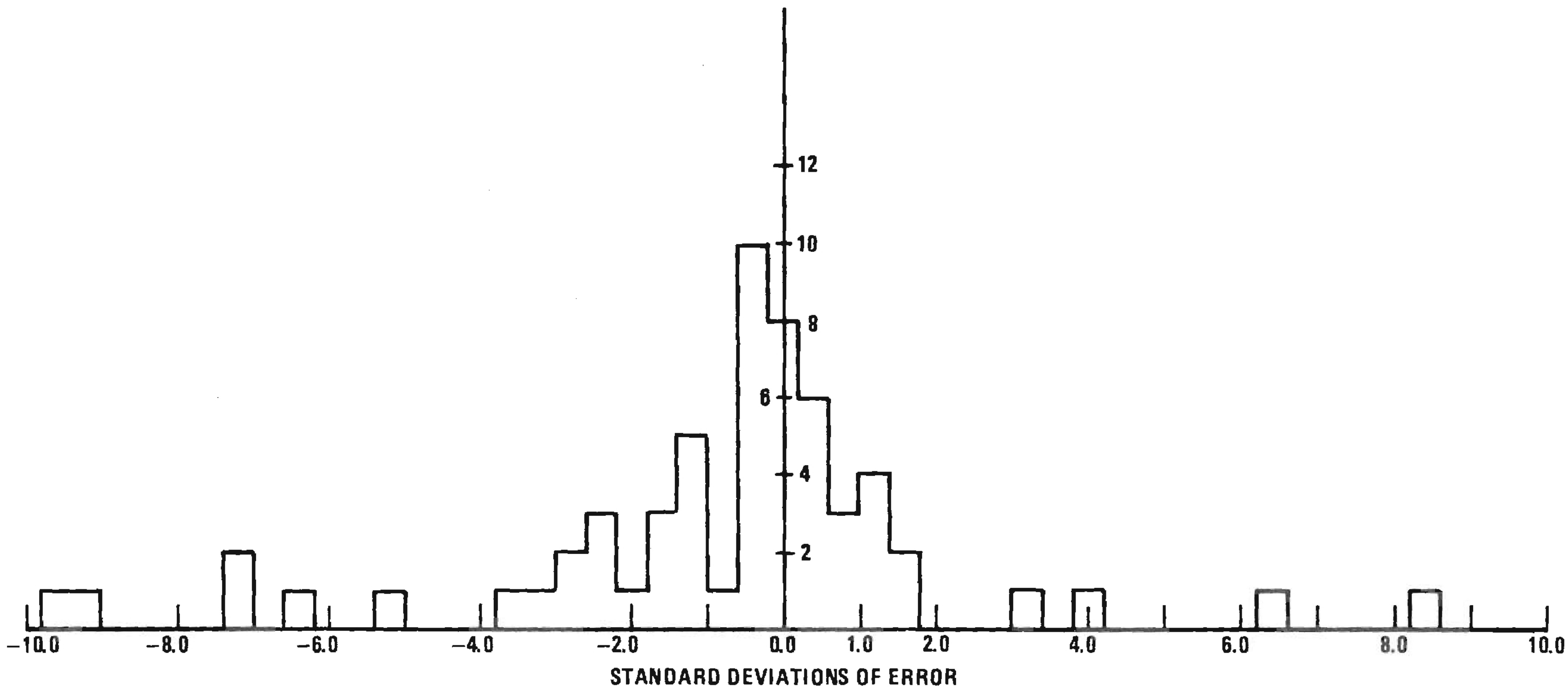


Fig. 6(a): Histogram of State Estimator Normalized Residuals Prior to Parameter Estimation (Time sample No. 15)

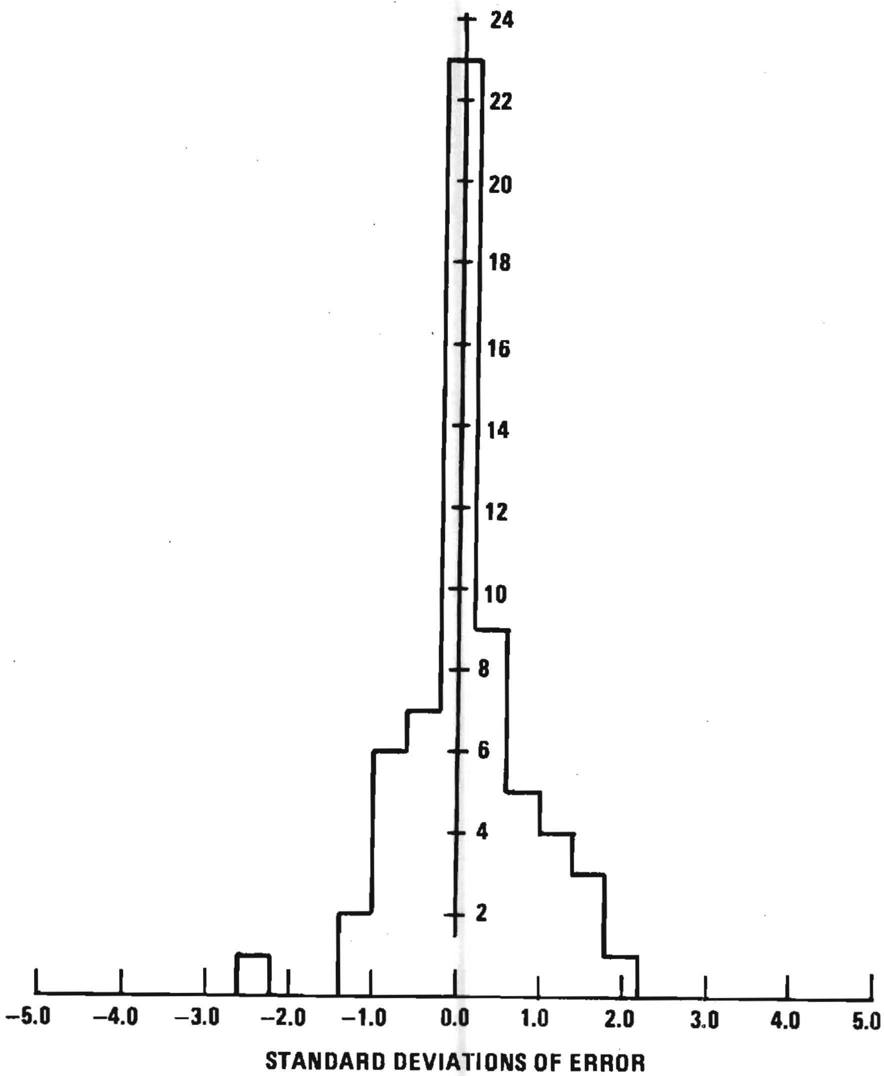


Fig. 6(b): Histogram of State Estimator Normalized Residuals After Parameter Estimation (Time Sample No. 15) about a general level of network parameter inaccuracy of 5-10%.

In Figure (2), the actual results were obtained after deleting all reactive measurements at the transformer banks. This caused the sensitivity of the performance index to transformer parameter errors to be small. Unfortunately, time did not permit to upgrade this algorithm to estimate transformer leakage susceptance and the tap at the fixed end. The algorithm, however, did estimate transmission line series susceptances and shunt capacitances. The performance improved from a value of 4.5 to .8-1.4.

For the remainder of the report, all results pertain to the decoupled State-Parameter Algorithm.

4.3.3 Overall Performance

The performance index defined in Eq. (1) is plotted as a function of time samples before and after performing parameter estimation as shown in Figure (5). Two aspects can be noted here. First, an improvement in performance of at least one order of magnitude is observed due to parameter estimation. The second is that a slight reduction in measurement errors is observed as loading conditions decrease in magnitude from noon to evening and then to midnight. This demonstrates the assumption that measurement errors generally increase with increasing load conditions. It is noted that the formulas for measurement variances given in Eqs. (12) and (13) were used only for the first time sample and then the variances were held constant. A variable σ for each time sample would, most probably, yield a fairly constant performance index.

Figure (6) shows the histograms of normalized residuals r_i defined as:

$$r_i = \frac{z_i - h_i(\hat{x},\hat{p})}{\sigma_i} \; ; \; i=1,\ldots,m.$$

It is clear from this figure that all the large errors which are statistically unacceptable have been eliminated by the parameter estimation process. Furthermore the distribution of errors following parameter estimation is approximately Gaussian. It is felt that this is an interesting result which justifies to a good extent, The Gaussian assumption about measurement noise.

4.3.4. Transmission Line Parameters

The parameter estimation program attempted the estimation of line susceptances only. From a sensitivity analysis point of view it can be shown that small errors in line conductances and shunt capacitances are of little consequence. This was confirmed by simulation tests whereby very minor performance degradation was observed due to these parameters.

Table II shows the initial and final values of transmission line susceptances. Changes greater than 10% in these values occured in 4 of the 14 lines shown. A change of 38.1% was observed on the last line in the list. Comparison of measured with estimated flows, both before and after parameter estimation, is provided in Figure (7). As can be expected, parameter estimation does the job of reducing the values of the residuals.

4.3.5 Transformer Parameters

In the case of transformers several modifications to our prior assessments had to be made. In Ref. (4) it was advocated that transformer tap settings should be estimated. No attempt was made to estimate leakage susceptances. After considerable evaluation of results it was concluded that it is more meaningful to estimate a) transformer leakage susceptance and b) the fixed tap settings which are constant. The variable tap settings are directly measured.

TABLE II: Comparison of Given and Estimated Susceptances (B) of all Transmission Lines

LINE	GIVEN B	ESTIMATED B	DIFFERENCE	%DIFFERENCE
BONN2-ROSS2	17.7648	18.1002	.3354	1.91%
BONN2-TRO T	29.9539	30.1022	.1482	.443%
O CTY9-KEELR9	199.8990	228.1128	28.2137	12.65%
BONN2-TROUT2	22.5949	22.1232	-.4717	-2.14%
RIVGT2-ROSS2	107.8550	127.4719	19.6169	15.30%
ROSS2-TRO T	42.8996	40.1044	-2.7953	-7.22%
TROUT2 TRO T	92.1934	90.7880	-1.4053	-1.53%
ROSS2-ALCOA2	160.6944	159.9392	-.7553	-.47%
OSTRN9-O CTY9	178.7614	212.7244	33.9631	15.9%
ST JN2-ROSS2	89.0228	88.7825	-.2404	-.27%
TROUT9-OSTRN9	195.1089	195.0905	-.0184	-.01%
KEELR2-RIVGT2	66.6669	61.6149	-5.052	-8.2%
KEELR1-O CTY1	7.4684	6.8251	-.6432	-9.45%
KEELR1-ST JN1	14.7558	23.8421	9.0683	38.1%

TABLE III: Comparison of Given and Estimated Transformer Series Admittances (B) of all Transformers

TRANSFORMER	GIVEN B	ESTIMATED B	DIFFERENCE	%DIFFERENCE
TROUT9-TROUT2	83.6854	83.6776	.0078	.009%
ROSS1-ROSS2(1)	33.3146	37.4421	4.13	11.02%
ROSS1-ROSS2(2)	33.7209	36.7527	3.032	8.25%
ALCOA1-ALCOA2	34.5639	34.4084	-.1555	-.452%
KEELR9-KEELR2	87.7133	92.1847	4.47	4.85%
ST JN2-ST JN1	38.0219	37.93	4.47	4.58%
KEELR2-KEELR1(1)	37.3351	42.8753	-.092	-.242%
KEELR2-KEELR1(2)	38.2457	37.5748	-.671	-1.78%

TABLE IV: Comparison of Given and Estimated Transformer Tap Ratios for all Transformers

TRANSFORMER	GIVEN TAP	ESTIMATED TAP	DIFFERENCE	%DIFFERENCE
TROUT9-TROUT2	.9762	.9762	0.0	0.0
ROSS1-ROSS2(1)	1.0122	1.0066	-.0056	-.55%
ROSS1-ROSS2(2)	1.000	1.0061	.0061	-.60%
ALCOA1-ALCOA2	.9756	.9758	.0002	.02%
KEELR9-KEELR2	.9762	.9741	-.0021	-.22%
ST JN2-ST JN1	.9685	.9687	.0002	.02%
KEELR2-KEELR1(1)	1.050	1.0037	-.0436	-4.3%
KEELR2-KEELR1(2)	1.025	1.0038	-.0212	-2.1%

Tables III and IV compare initial and final values of transformer susceptances and tap ratios respectively. Figure (8) provides comparisons of measured vs estimated flows at various transformers. Some fairly serious discrepencies can be observed at the ROSS1-ROSS2 and KEELR1-KEELR2 transformer banks.

4.3.6 Discussion of Results

Based on the above results and also the mass of information acquired during the testing period, it can be safely concluded that our prior suspicions regarding the network modeling problem were justified. This could not be more true then in the case of transformers. By deleting the reactive flows at the transformers banks from the estimation process, the estimates of these flows have errors of approximately several hundred MVAR's. In Fig. (8) the error is still over 100 MVAR's although these measurements were included in the estimation process.

In the case of transmission lines the case of 38.1% error seems to be amomalous. However, the other errors seem to be within theoretical predictions.

The main result of the above tests, we feel, is that we have a good tool to work with to simultaneously improve the accuracy of network parameters and identify sources of discrepancy in the model.

5. PROCEDURES FOR ON-LINE IMPLEMENTATION

5.1 Implementation Phases and Requirements

Successful implementation of BPA's on-line state estimator will depend on several software developments and the coordination of several activities. The primary activities involved are:

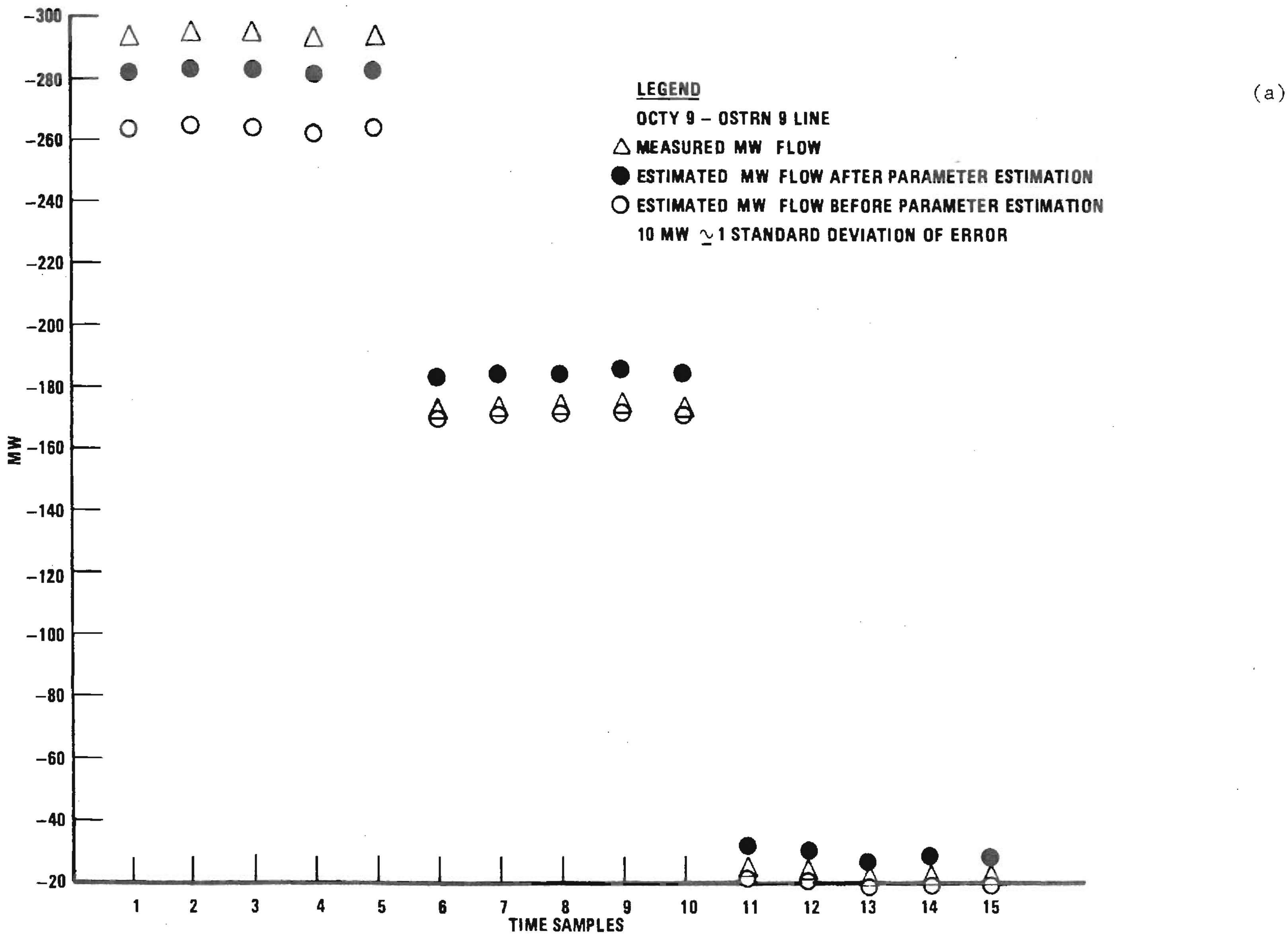
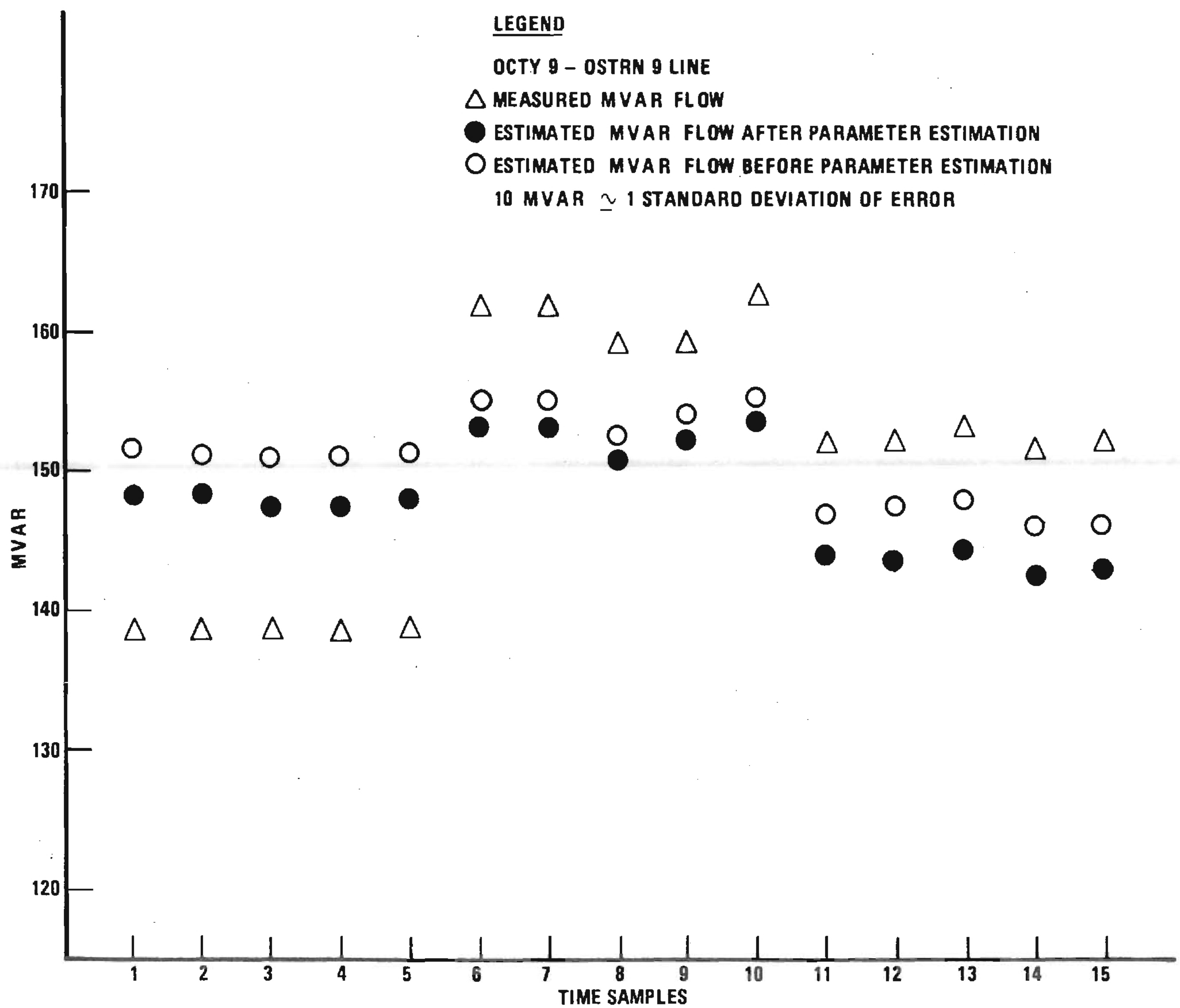
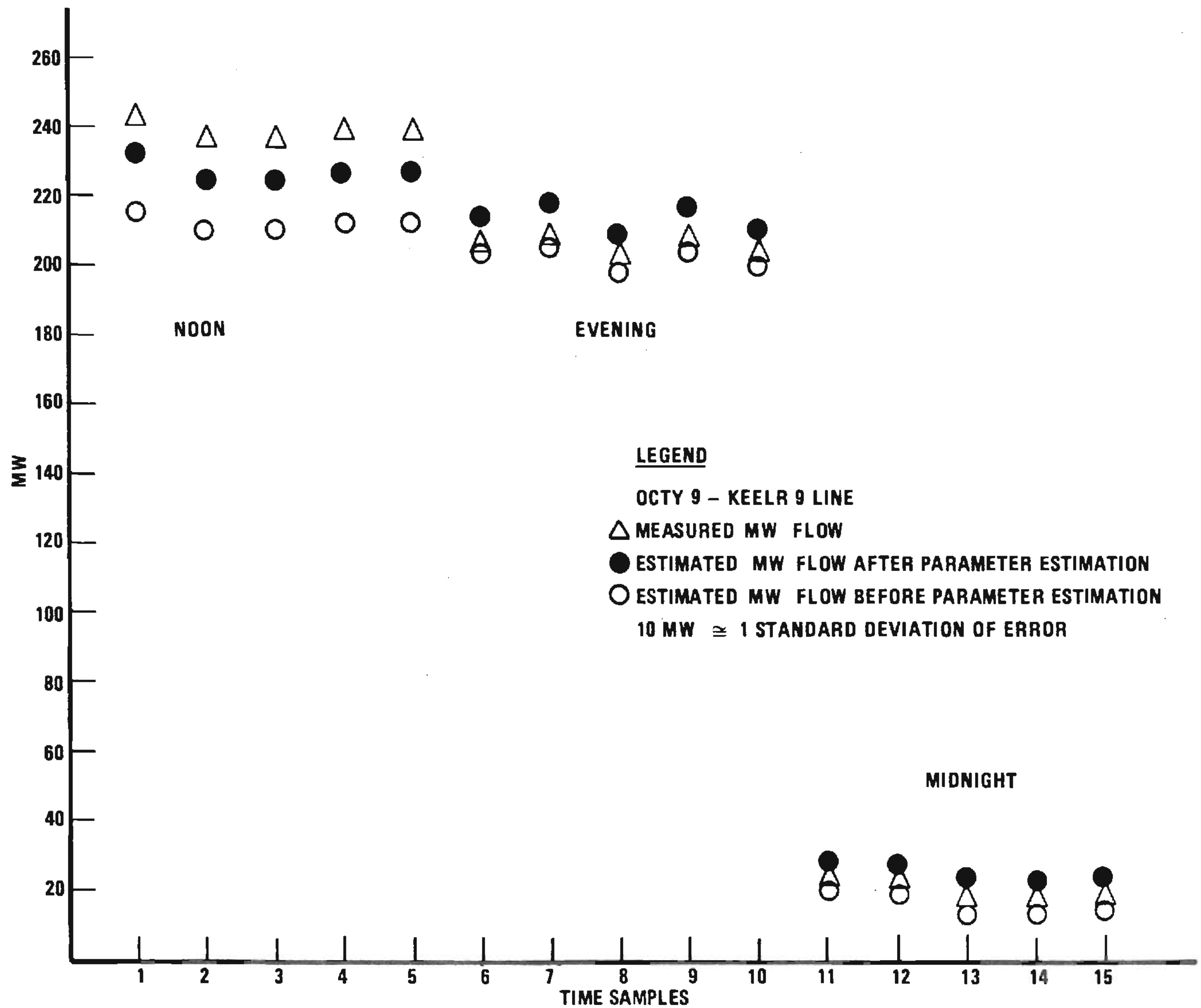


Fig. 7(a-e): Comparison of Measured with Estimated Flows on Transmission Line before and after Parameter Estimation.

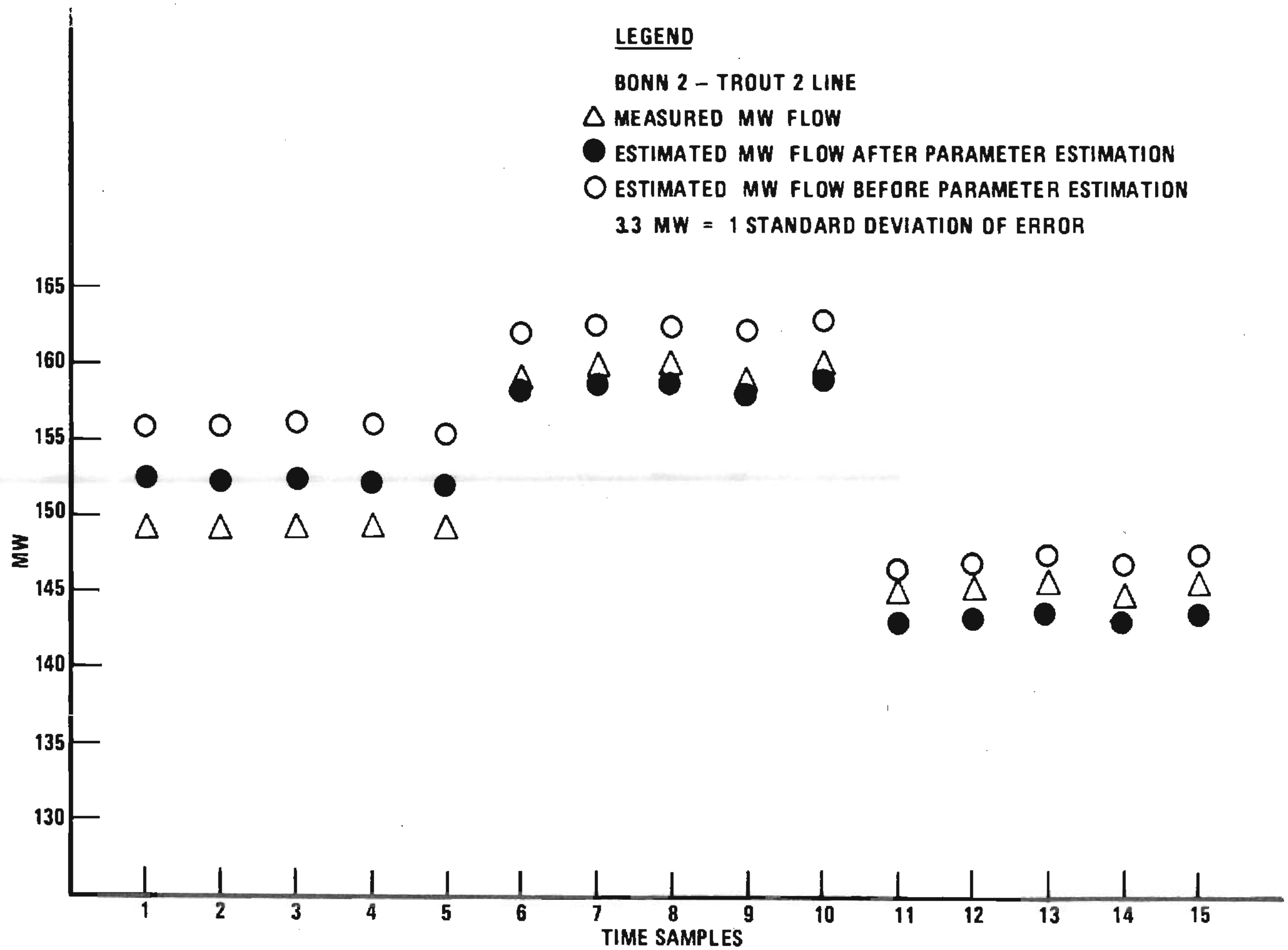
(b)


LEGEND
OCTY 9 – OSTRN 9 LINE
MEASURED MVAR FLOW
ESTIMATED MVAR FLOW AFTER PARAMETER ESTIMATION
ESTIMATED MVAR FLOW BEFORE PARAMETER ESTIMATION
10 MVAR ≃ 1 STANDARD DEVIATION OF ERROR
MVAR
170
160
150
140
130
120
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
TIME SAMPLES

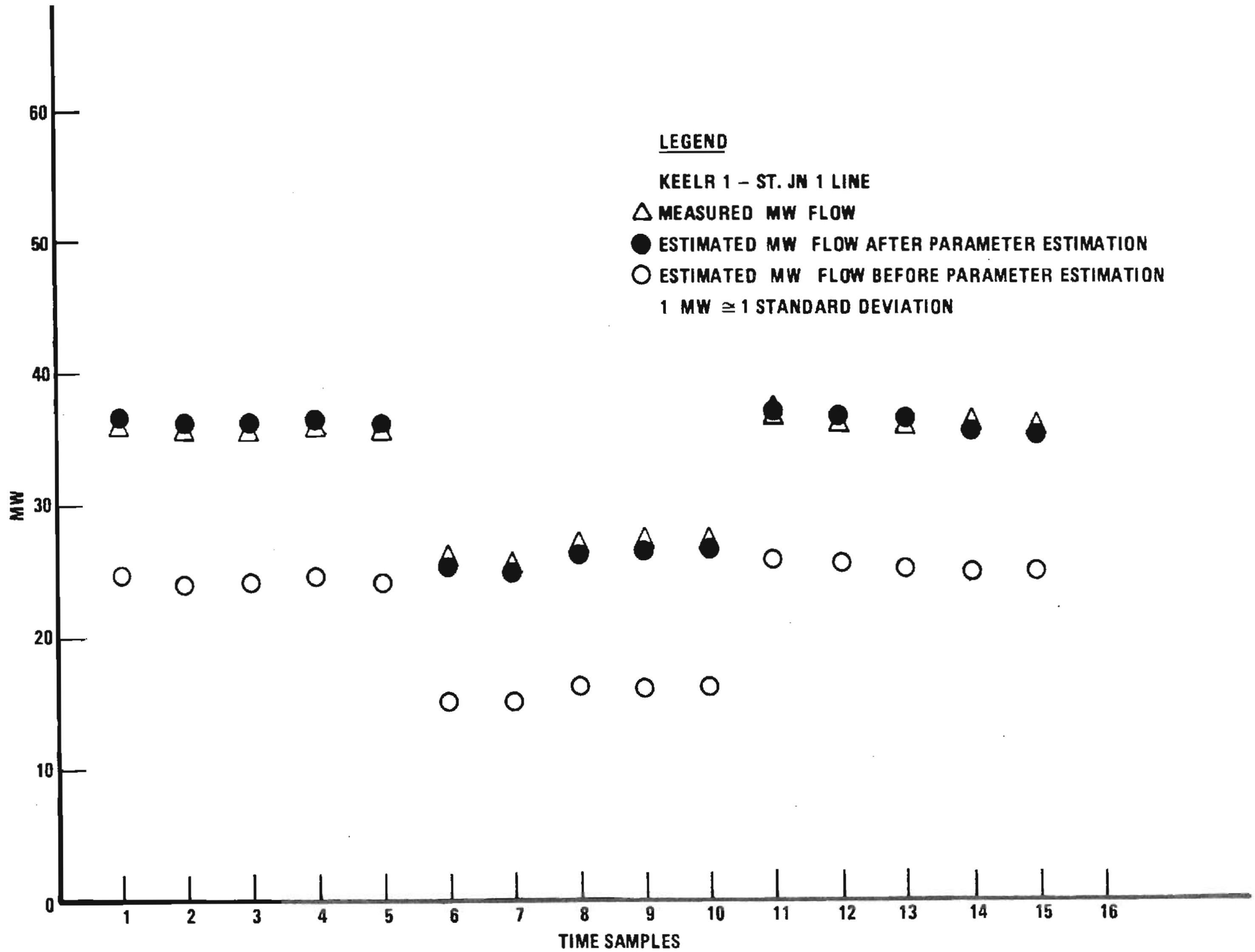
(c)


260
240
220
200
180
160
140
120
100
80
60
40
20
MW
NOON
EVENING
MIDNIGHT
LEGEND
OCTY 9 – KEELR 9 LINE
MEASURED MW FLOW
ESTIMATED MW FLOW AFTER PARAMETER ESTIMATION
ESTIMATED MW FLOW BEFORE PARAMETER ESTIMATION
10 MW ≅ 1 STANDARD DEVIATION OF ERROR
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
TIME SAMPLES

(d)


LEGEND
BONN 2 – TROUT 2 LINE
MEASURED MW FLOW
ESTIMATED MW FLOW AFTER PARAMETER ESTIMATION
ESTIMATED MW FLOW BEFORE PARAMETER ESTIMATION
3.3 MW = 1 STANDARD DEVIATION OF ERROR
MW
165
160
155
150
145
140
135
130
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
TIME SAMPLES

(e)


LEGEND
KEELR 1 – ST. JN 1 LINE
MEASURED MW FLOW
ESTIMATED MW FLOW AFTER PARAMETER ESTIMATION
ESTIMATED MW FLOW BEFORE PARAMETER ESTIMATION
1 MW ≅ 1 STANDARD DEVIATION
MW
0
10
20
30
40
50
60
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16
TIME SAMPLES

(a)

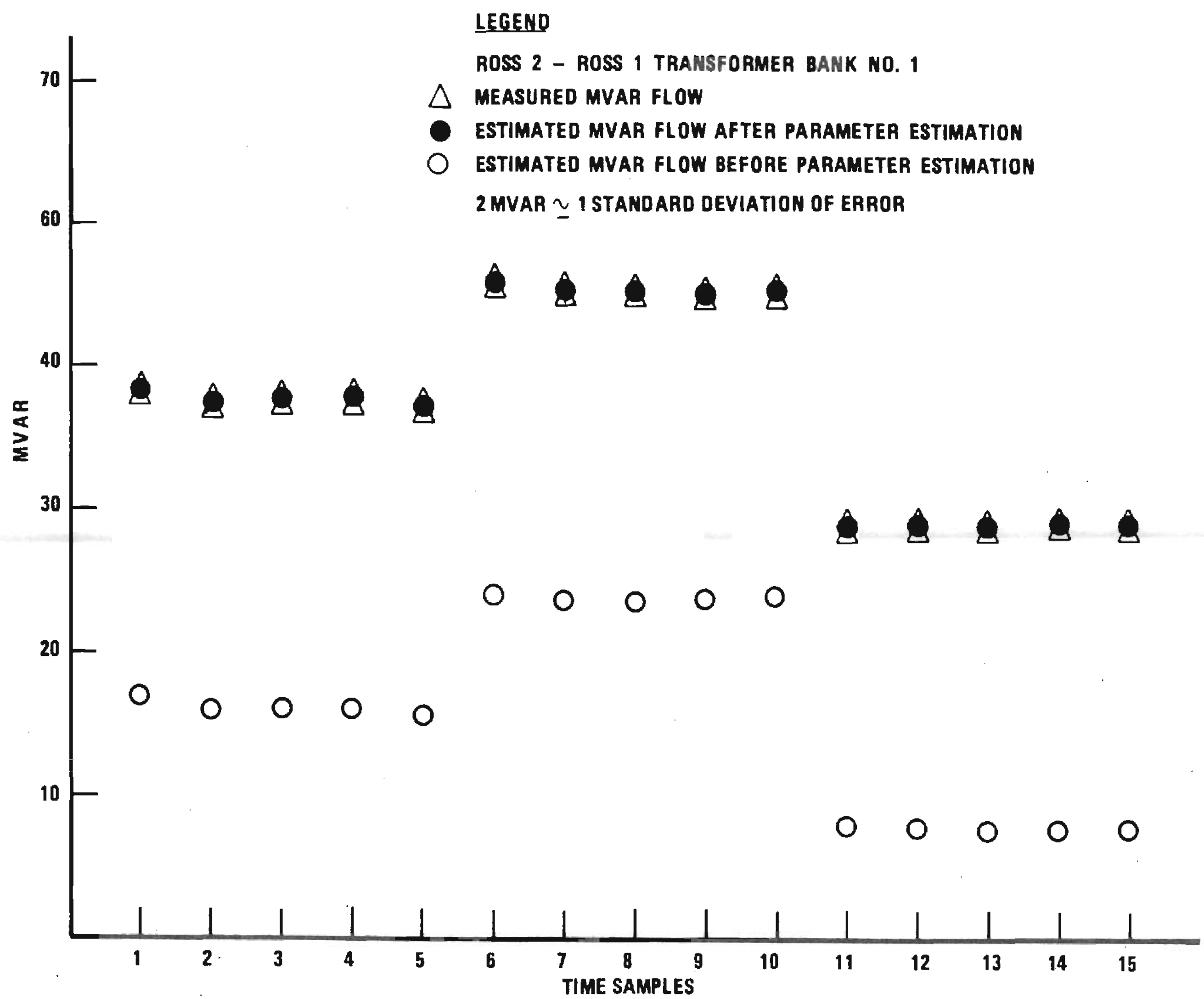
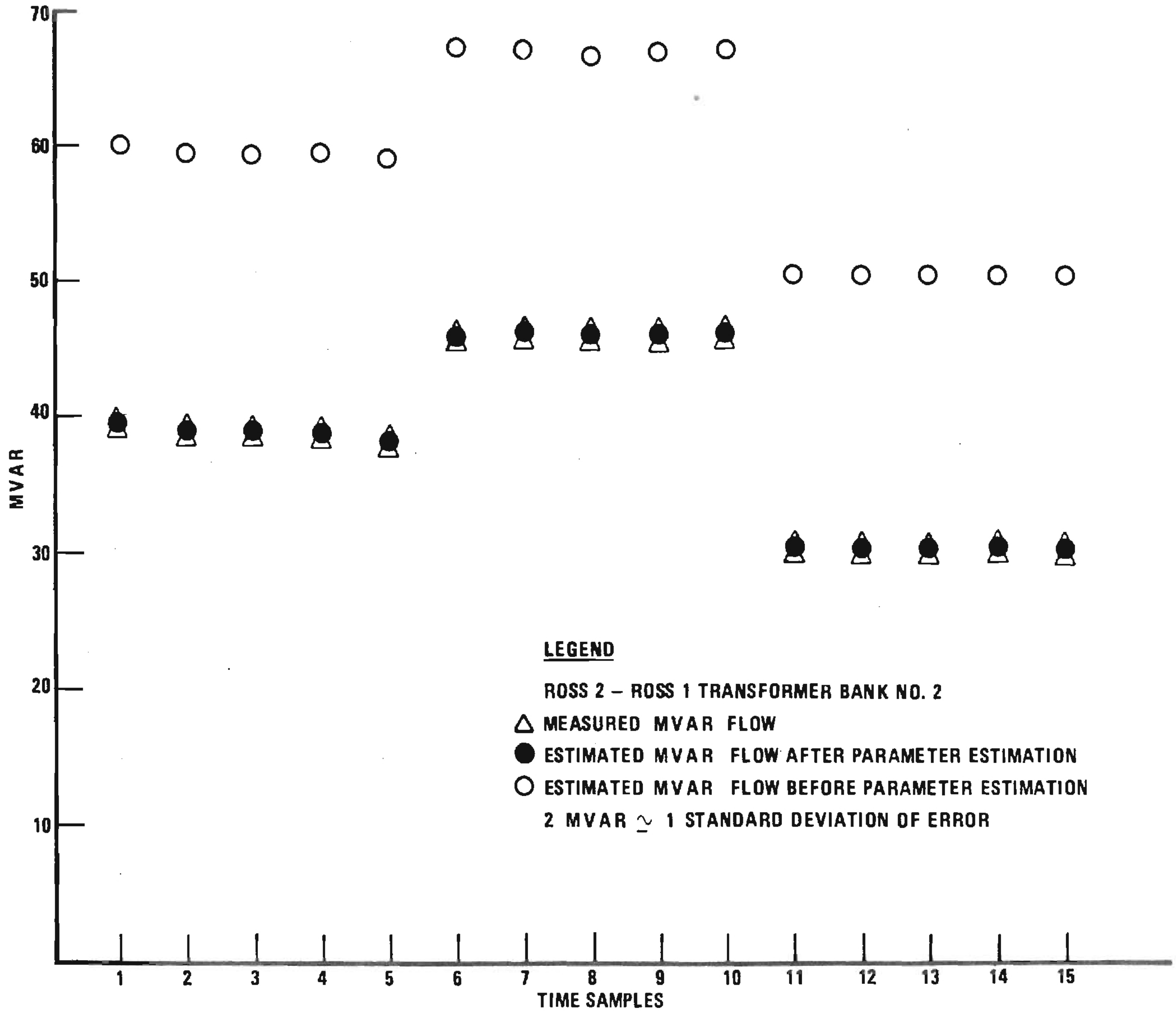
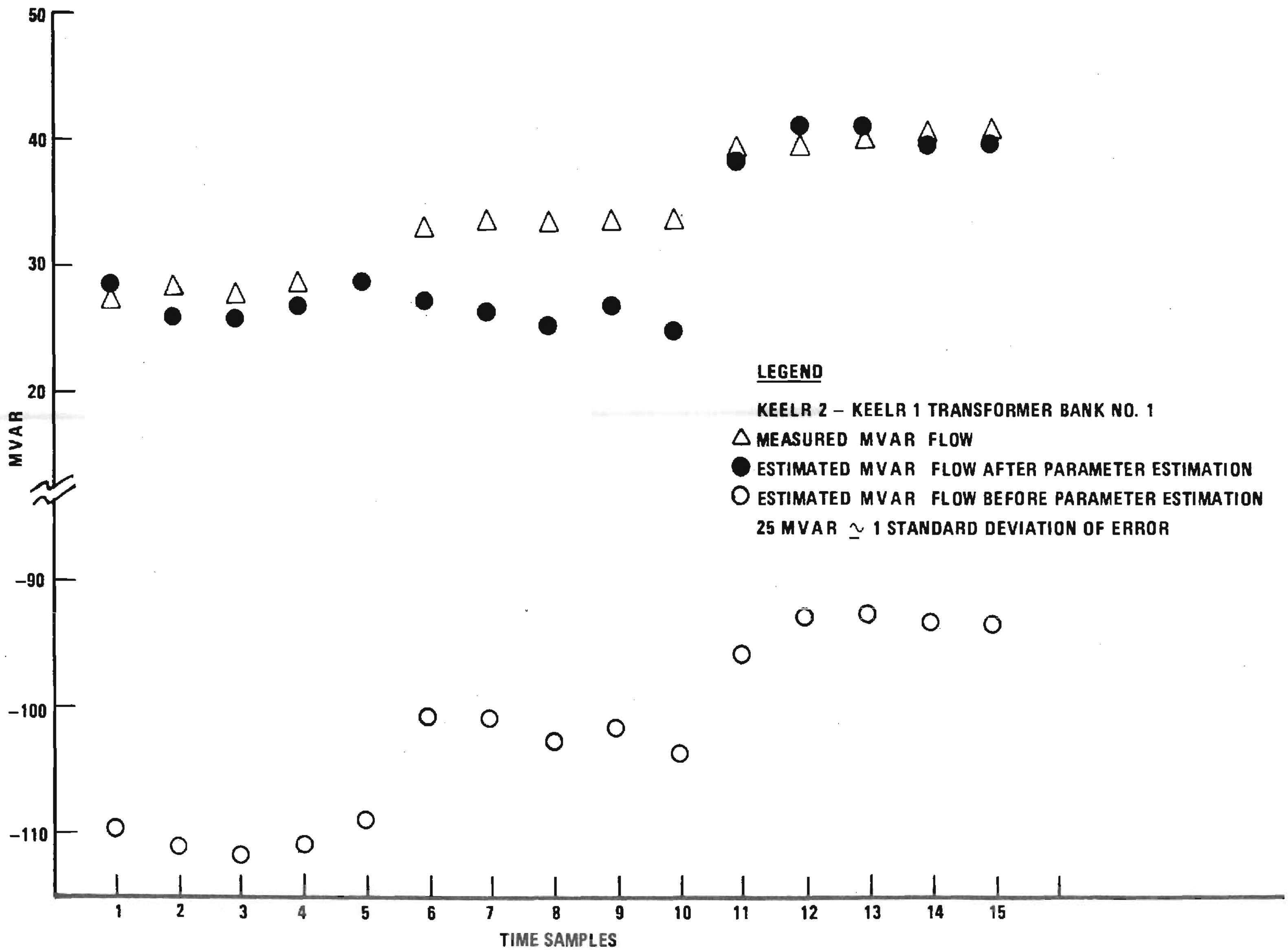


Fig. 8(a-d): Comparison of Measured with Estimated Flows on Some Transformer Banks

(b)

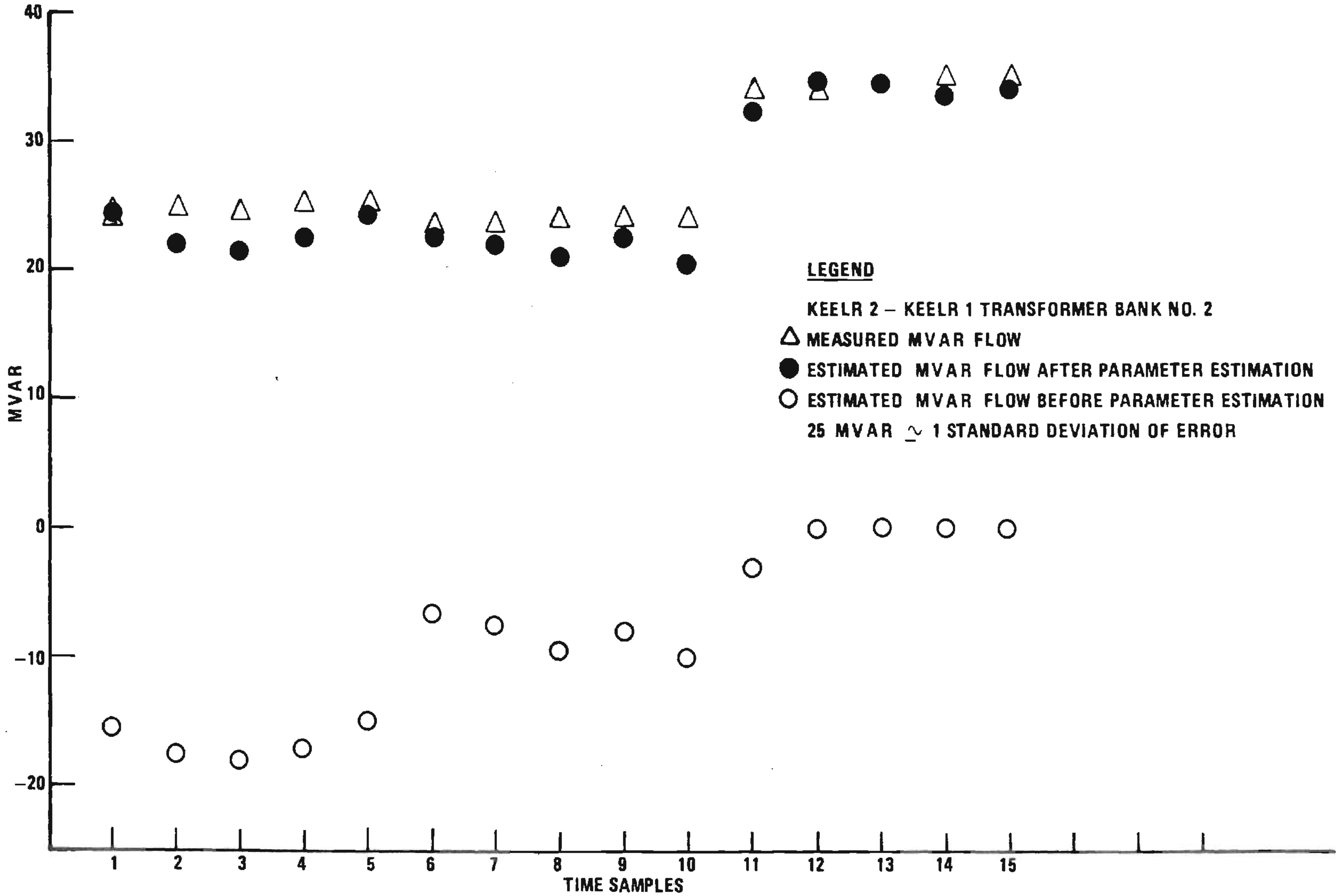

MVAR
70
60
50
40
30
20
10
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
TIME SAMPLES
LEGEND
ROSS 2 – ROSS 1 TRANSFORMER BANK NO. 2
MEASURED MVAR FLOW
ESTIMATED MVAR FLOW AFTER PARAMETER ESTIMATION
ESTIMATED MVAR FLOW BEFORE PARAMETER ESTIMATION
2 MVAR $\underset{-}{\sim}$ 1 STANDARD DEVIATION OF ERROR

(c)



50
40
30
20
MVAR
-90
-100
-110
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
TIME SAMPLES
LEGEND
KEELR 2 – KEELR 1 TRANSFORMER BANK NO. 1
△ MEASURED MVAR FLOW
● ESTIMATED MVAR FLOW AFTER PARAMETER ESTIMATION
○ ESTIMATED MVAR FLOW BEFORE PARAMETER ESTIMATION
25 MVAR ≃ 1 STANDARD DEVIATION OF ERROR

(d)



40
30
20
10
0
−10
−20
MVAR
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
TIME SAMPLES
LEGEND
KEELR 2 – KEELR 1 TRANSFORMER BANK NO. 2
MEASURED MVAR FLOW
ESTIMATED MVAR FLOW AFTER PARAMETER ESTIMATION
ESTIMATED MVAR FLOW BEFORE PARAMETER ESTIMATION
25 MVAR ≃ 1 STANDARD DEVIATION OF ERROR

a. Implementation of all software associated with the Sequential State Estimator,

b. Implementation of parameter estimation software,

c. Evaluation of operator requirements and confidence in state estimation,

d. Evaluation of scheduling requirements of performing state estimation based on collected system-wide data, and

e. Tuning of all kinds of relevant parameters prior to commissioning of the on-line estimator.

Remaining portions of the overall package contain subroutines for the detection and diagnosis of bad data. Full implementation and testing of these has not been performed yet.

Finally, programs which generate network configuration from SCADA outputs are yet to be fully developed and completed. This is a fairly difficult and obviously crucial program. It is essential that it becomes available as soon as possible.

5.2 Parameter Estimation

The two parameter estimation programs which have been developed are compatible with the state estimation package. In essence they use the same inputs and produce the same outputs except for outputs on network admittance parameters. Further refinements in these programs are necessary. These are:

(a) Program cleanup which requires deletion of some unnecessary subroutines

(b) Increase in capability to handle large networks.

This may involve some extended core storage programming

(c) Implementation of a better bus/parameter ordering scheme

(d) Detailed program documentation

A by-product of the parameter estimation program is the weighted least squares estimation program using sparsity techniques. Any improvements on the parameter estimation package will automatically apply to this program.

5.3 Operator Requirements

During the full-scale testing period, serious effort should be associated with overall operator requirements from the points of view of

(a) Display requirements

(b) Understanding of the estimation program, and

(c) Developing his confidence in the results.

All of these items are interrelated since a good deal of interaction, his confidence in the estimation process will, hopefull, grow.

5.4 Frequency of Updates

Studies which use actual system-wide data should be performed to determine the required frequency of updating the state estimates. These studies should be based on the following requirements:

(a) Operator display

(b) Bus-load forecasting

(c) Security monitor, and

(d) Voltage scheduling.

The objective should be to satisfy all these requirements while minimizing computer time requirements. It is hoped that this will considerably reduce computational time requirements of state estimation. The data obtained during the study period indicated the changes in system operating conditions are very small even over a range of ten minutes. However, this may be characteristic only of the particular area monitored. Not enough information was available for system-wide assessment over a day or so.

The approach which we proposed contemplated using information about the time behavior of bus loads and generations. And by means of a simple prediction scheme (simplified bus-load forecaster) the decision is made when the next state estimate is necessary. This would make the process of when to compute state estimates adaptive. The predictor will determine also when to attempt security assessment next. Hence, there are overall savings in computer time for both state estimation and the rest of the applications programs.

Alternatively, however, display and bus-load forecasting requirements are better satisfied with periodic state estimator updates. Hence, an optimum solution should be reached which takes into account all of the above factors.

5.5 Testing and Tuning

Prior to final commissioning of the on-line estimator many of the tests conducted so far and others should be performed on a system-wide and thorough basis. These will consist of:

(a) Very careful calibration of instrumentation and testing of any discrepancies arising in the metering process.

(b) Evaluation of any inadequacies in the network configuration which is based on status information.

(c) Careful checking of network models with special emphasis on transformers, status of capacitor banks, and all the required model changes due to status changes (e.g. 3-winding transformers).

(d) Testing of statistical model validity without attempting any parameter estimation.

(e) Tuning of network models by means of parameter estimation.

(f) Examination, through field tests, analysis of data, discussions with operators, etc. of any serious discrepancies in the network models which might arise following parameter estimation.

(g) Tuning of the sequential state estimator using all the validated models.

5.6 Conclusions and Recommendations

The basic conclusions of the present study are:

(a) Modeling problems do exist as far as network parameters are concerned.

(b) These problems cause the state estimator to provide fairly unreliable results whereby considerable discrepancies between some measured and estimated quantities exist.

(c) Parameter estimation can clean-up the network parameter models leading to statistically acceptable results.

(d) There is still a significant role for field tests and engineering judgement in the modeling area. This should be exercised. Parameter estimation can easily pinpoint the areas of possible trouble and discrepancies.

(e) Improved tuning procedures for the sequential state estimator were developed and implemented.

In my recommendations for future developments, the following items are stressed:

(a) The final stages of software development as described in the previous section should be undertaken with speed to insure early state estimator implementation.

(b) Closer interaction among analysts, system operators, and programmers will be required to insure a proper understanding of the whole process and to develop the required confidence in it.

(c) The immediate next step will be the model validation of all parameters associated with security monitoring. The present NSF supported work (with BPA's endorsement) is quite significant in developing the basic concepts. These will have to be tested for feasibility from the practical point of view. It is hoped that as a result of concerted effort a valid security monitor will result.

IDENTIFICATION OF EXTERNAL NETWORK EQUIVALENTS

1. BACKGROUND

In recent years advanced techniques (21-23) have been implemented to assure a secure electric power service under all conditions of operation. The system operator is concerned with different inequality constraints (frequency drops, overloading of lines, etc.) and with equality constraints (generation meets the demand).

The conditions of operation of a power system may be categorized into three basic states:

(1) Normal state

(2) Emergency state

(3) Restorative state

In the Normal state, all system equality and inequality constraints are satisfied. In the Emergency state, some of the inequality constraints are violated. In the Restorative state some of the equality constraints are violated.

The Normal state can be decomposed into two states:

(1) Secure Normal State

(2) Insecure Normal State

A Secure Normal state is a Normal state where single system contingencies like the loss of aline or a generator will not cause departure from the Normal state. An Insecure Normal state is a Normal state where single system contingencies can cause a departure to an emergency state.

Figure 8 shows the several operating states and the associated control strategies.

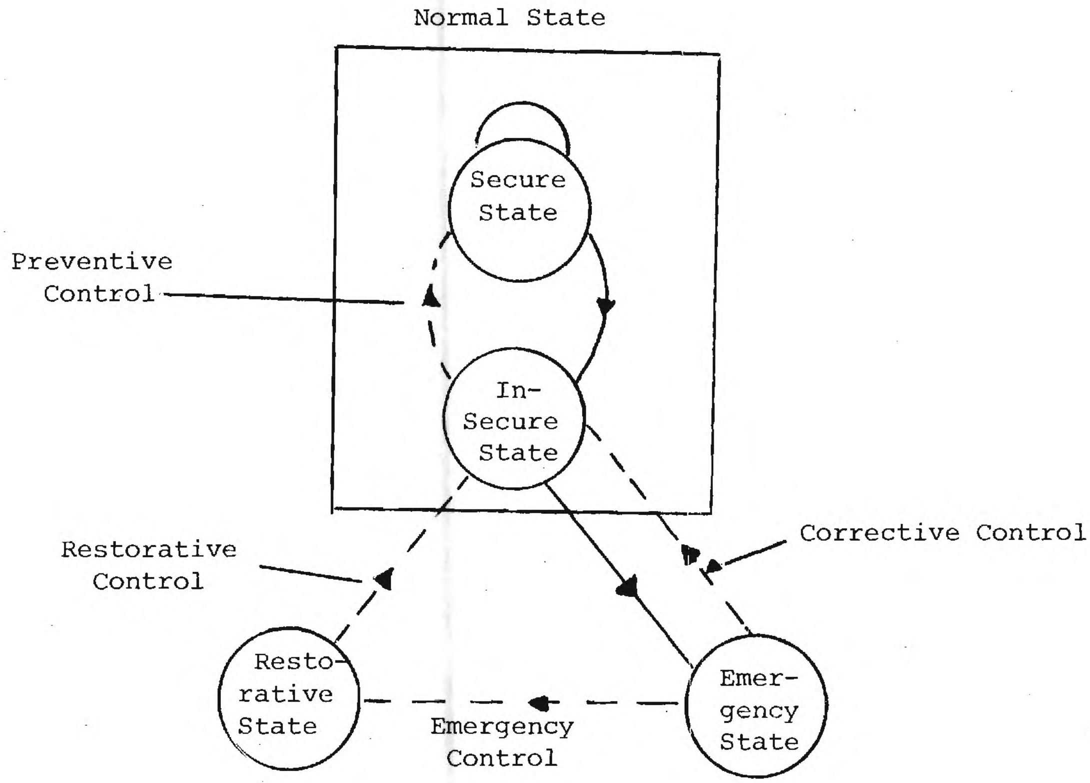


FIG. 8. Interactions Among Power System Operating States

The primary concern of the system operator is to keep the operating condition of the power system in the Normal state to ensure service continuity at standard frequency and voltage. The operator should continuously test the capability of the power system to withstand postulated next contingencies in order to judge its level of vulnerability. If the contingency analysis indicates that the system is in Secure Normal state, no control action is needed. If, however, the contingency analysis indicates that the system is in Insecure Normal state, preventive control action should be taken to bring the system in Secure Normal state in the most economical way. This preventive control action may involve shifting of generation schedules, switching operations, start-up of units or changing the scheduled exchange of power with neighboring systems.

The above introduction shows the importance of the contingency analysis in the security assessment of power systems.

Contingency analysis involves the solution of a load flow problem once for each contingency. The process involves two steps:

(a) Computation of a load flow solution of the present operating condition of the system using on-line state estimation.(15)

(b) Computation of the load flow solution of the system for the various single line or generator outages.(24-26)

Interconnections with neighboring systems considerably influence the redistribution of network power flows and voltage levels after outages take place. Therefore step (b) above requires the knowledge of the precontingency load flow solution of the neighboring system. Since this is difficult to achieve at present, an equivalent representation of the neighboring (external) system becomes necessary.

The existing approaches to obtain the equivalent representation of the external system can be classified into two categories.

(1) Norton-type equivalents: To obtain a Norton-type equivalent knowledge of the topology and network parameters of the external system is necessary.

(2) On-line type equivalents: On-line type equivalents assume no knowledge about the external system and they use information from the internal system only to obtain the equivalent representation of the external system.

We should emphasize that equivalence techniques are apllied also for planning purposes but for different reasons than for on-line security assessment. On planning the primary purpose of the network reduction is to avoid the computational burden of solving the load flow for the entire area.

2. AVAILABLE METHODS

In any network equivalencing problem the overall area is divided into an internal system and an external system as it is shown in Figure 9. Some buses of the internal system are connected to the external system. These buses are called the boundary buses.

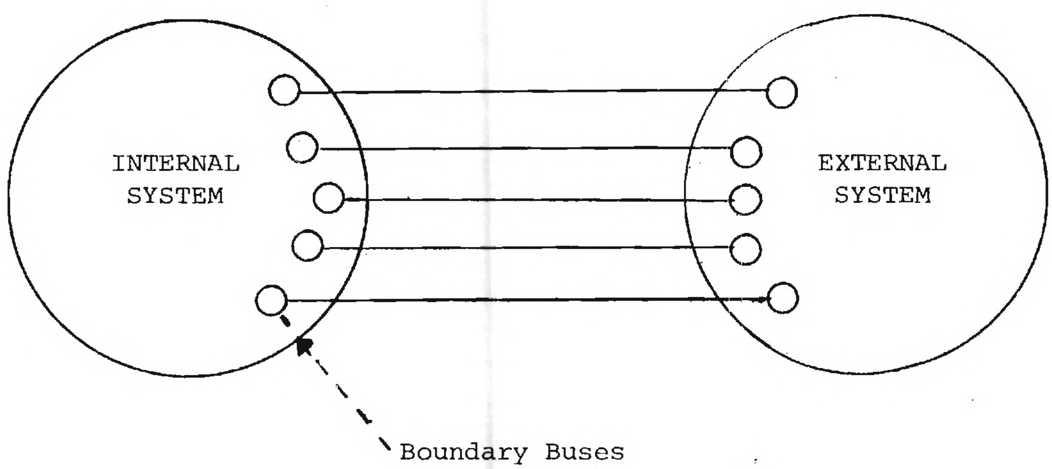


FIG. 9. Decomposition of System in Internal and External Parts

The entire system nodal matrix equation is

$$Y\underline{V} = \underline{I} \tag{19}$$

where $\underline{I}$, $\underline{V}$ are the vectors of injected bus currents and bus voltages respectively and Y is the system's nodal admittance matrix. The vectors $\underline{I}$, $\underline{V}$, and the matrix Y can be written as:

$$\underline{V} = \begin{bmatrix} \underline{V}_E \\ \underline{V}_B \\ \underline{V}_I \end{bmatrix}, \quad I = \begin{bmatrix} \underline{I}_E \\ \underline{I}_B \\ \underline{I}_I \end{bmatrix}, \quad Y = \begin{bmatrix} Y_{EE} & Y_{EB} & 0 \\ Y_{BE} & Y_{BB} & Y_{BI} \\ 0 & Y_{IB} & Y_{II} \end{bmatrix} \tag{20}$$

where the subscripts E, B, and I refer to external, boundary, and internal respectively. Following the above notation, one can write

$$\begin{bmatrix} Y_{EE} & Y_{EB} & 0 \\ Y_{BE} & Y_{BB} & Y_{BI} \\ 0 & Y_{IB} & Y_{II} \end{bmatrix} \begin{bmatrix} \underline{V}_E \\ \underline{V}_B \\ \underline{V}_I \end{bmatrix} = \begin{bmatrix} \underline{I}_E \\ \underline{I}_B \\ \underline{I}_I \end{bmatrix} \tag{21}$$

Elimination of $\underline{V}_E$ from Equation (3) yields:

$$\begin{bmatrix} Y_B - Y_{BE}Y_{EE}^{-1}Y_{EB} & Y_{BI} \\ Y_{IB} & Y_{II} \end{bmatrix} \begin{bmatrix} \underline{V}_B \\ \underline{V}_I \end{bmatrix} = \begin{bmatrix} \underline{I}_B - Y_{BE}Y_{EE}^{-1}\underline{I}_E \\ \underline{I}_I \end{bmatrix} \tag{22}$$

This is the equivalent nodal matrix equation for the internal system. If the equivalent nodal admittance matrix is known, together with the boundary and internal bus voltages, one can easily evaluate the equivalent injected currents from Equation (22). If these currents do not change following an internal network change, then network outage contingencies can be solved exactly.

The trouble here is that the equations describing the system are not those of Equation (19) but rather the load flow equations which are non linear. They consist of:

(a) Two equations per load bus, one for real and for reactive power.

(b) One equation per generation bus for real power. Voltage magnitudes for generating buses are fixed and known.

(c) No equations for slack bus where the voltage magnitude is known and the phase angle is fixed arbitrarily at zero.

In most of the approaches given in the literature the following steps are taken.

(a) Define the boundaries of the internal system.

(b) Reduce by means of Norton equivalent the external system to the boundary.

(c) Classify the boundary buses as generation buses or as load buses.

In reference (27) the internal system is augmented by a buffer zone as it is shown in Figure 10.

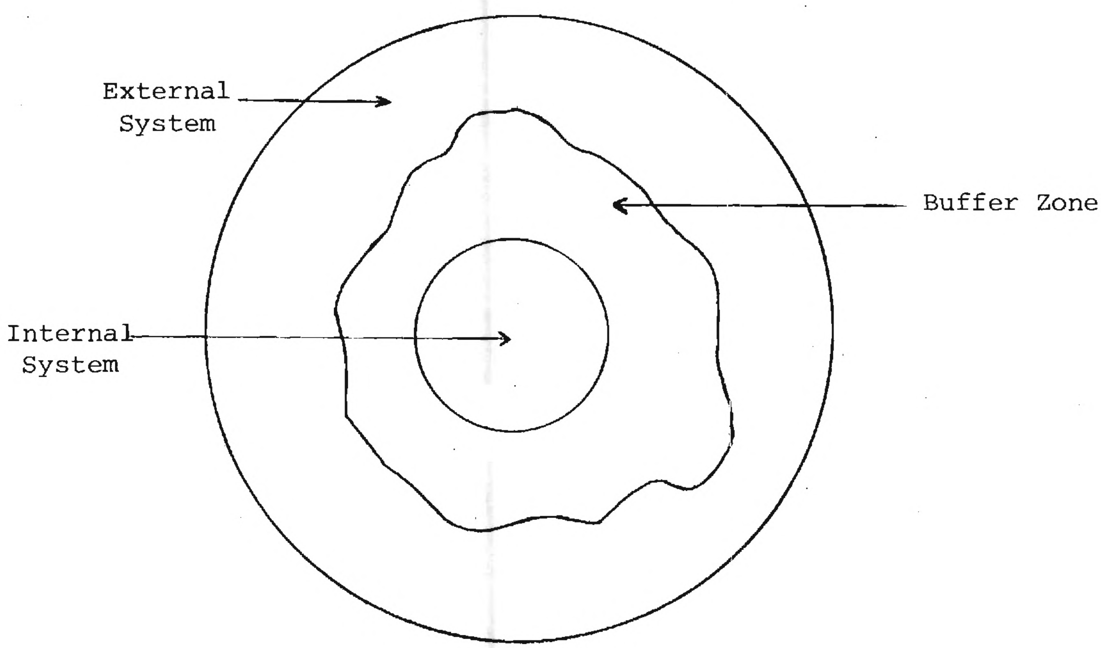


FIG. 10. Augmentation of Internal System by Means of a Buffer Zone

This buffer zone includes:

(1) Buses of the external system critical to the accuracy of the equivalent.

(2) Components of the external system of which the operational limitations may be violated due to disturbances in the internal system (weak links).

(3) Generation buses of the external system which control the operating conditions in the internal system (controlling buses).

The weak links are found by imposing extreme stressing conditions in the internal system. Since an unobservable part of the external system is included in the equivalent, several simplifications and assumptions are needed which jeopardize the accuracy of the equivalent system.

In reference (28) some buses of the external system are included in order to preserve sparsity in the equivalent representation. Simulation studies on power systems, however, have shown that the problem of sparse structure is not so crucial. Even if the number of the equivalent branches is extremely large, a portion of them may be eliminated by using a technique proposed in reference (29) or by a simpler method as we will propose later without significant sacrifice of the accuracy.

In reference (29) the boundary buses are assumed to be load buses; therefore, many of the equivalent branches between the boundary buses are eliminated by using, as criterion, the ratio

$$\frac{Z_{E,ij}}{Z_{T,ij}}$$

where $Z_{E,ij}$ is the impedance of the equivalent branch ij and $Z_{T,ij}$ is the corresponding transfer impedance given by the rest of the network. If

$$\frac{Z_{E,ij}}{Z_{T,ij}} > C \tag{23}$$

where C is a predetermined value, the branch ij is eliminated from the equivalent representation.

In references (30) and (31) two approaches are suggested. The first is a Norton-type equivalent where the boundary buses are treated as generation buses. The other is based on DC approximation of the external system. If $\underline{P}_B$ is the vector of tie line flows, one can write

$$\begin{bmatrix} \underline{P}_E \\ \underline{P}_B \end{bmatrix} = \begin{bmatrix} K_{EE} & K_{EB} \\ K_{BE} & K_{BB} \end{bmatrix} \begin{bmatrix} \underline{\theta}_E \\ \underline{\theta}_B \end{bmatrix} \tag{24}$$

Elimination of the vector θ_E yields

$$\begin{aligned} \underline{P}_B &= K_{BE}K_{EE}^{-1}P_E + (K_{BB} - K_{EE}^{-1}K_{EB})\underline{\theta}_B \\ &= G\underline{\theta}_B + H\underline{P}_E \end{aligned} \tag{25}$$

Since $\underline{P}_B$ and $\underline{\theta}_B$ are known, the vector

$$H\underline{P}_E = \underline{P}_B - G\underline{\theta}_B \tag{26}$$

is also known and it is assumed to be constant when a contingency occurs.

If

$$\underline{V} = \begin{bmatrix} \underline{V}_I \\ \underline{V}_B \end{bmatrix}$$

and

$$\underline{\theta} = \begin{bmatrix} \underline{\theta}_I \\ \underline{\theta}_B \end{bmatrix}$$

then the real and reactive injections in the internal system are

$$\underline{P}_I = \underline{P}_I(\underline{\theta},\underline{V}) \tag{27}$$

$$\underline{Q}_I = \underline{Q}_I(\underline{\theta},\underline{V}) \tag{28}$$

and

$$\underline{P}_B = \underline{P}_B(\underline{\theta},\underline{V}) \tag{29}$$

or by taking into consideration the linear approximation for the external system

$$\underline{P}_B(\underline{\theta},\underline{V}) + H\underline{P}_E + G\underline{\theta}_B = 0$$

or

$$-H\underline{P}_E = \underline{P}_B(\underline{\theta},\underline{V}) + G\underline{\theta}_B \tag{30}$$

Equations (27), (28), and (29) are the load flow equations. The boundary buses are assumed to be generation buses.

In reference (32) a model based on DC analysis is suggested. Deviations from the operating point are used to provide the necessary information for the equivalent representation. The statement of the method is:

The system between the boundary buses is modeled as

$$\underline{Z} = H\underline{u} + \underline{v} \tag{31}$$

where:

$\underline{Z}$ - is the vector of the phase angles of the boundary buses

$\underline{H}$ - is the unknown boundary impedance matrix

$\underline{u}$ - is the vector of real powers which depend upon the topology and real injections of the internal system

$\underline{v}$ - is the vector which depends upon the topology and real injections of the external system.

If

$$\begin{aligned}
\underline{Z}(n) &= \underline{Z}(t_{n+1}) - \underline{Z}(t_n) \\
\underline{u}(n) &= \underline{u}(t_{n+1}) - \underline{u}(t_n) \\
\underline{v}(n) &= \underline{v}(t_{n+1}) - \underline{v}(t_n)
\end{aligned} \tag{32}$$

then

$$\underline{Z}(n) = H\underline{u}(n) + \underline{v}(n) \tag{33}$$

It is assumed that $\underline{v}(n)$ has zero expected value and covariance matrix $E\{\underline{v}(n_1)\underline{v}^T(n_2)\} = R \cdot \delta(n_1 - n_2)$. Furthermore, $\underline{u}(n)$ and $\underline{v}(n)$ are uncorrelated. The problem is to estimate H and R by using $\underline{Z}(n)$, $n = 1, \ldots, N$ where N is the number of observations.

Least squares estimation yields

$$\hat{H} = [\sum_{n=1}^{N} \underline{Z}(n)\underline{u}^T(n)][\sum_{n=1}^{N} \underline{u}(n)\underline{u}^T(n)]^{-1} \tag{34}$$

$$\hat{R} = \frac{1}{N} \sum_{n=1}^{N} (\underline{Z}(n) - H\underline{u}(n))(\underline{Z}(n) - H\underline{u}(n))^T \tag{35}$$

provided that the inverse of

$$\sum_{n=1}^{N} \underline{u}(n)\underline{u}^T(n) \tag{36}$$

exists.

Objections to this approach are:

(1) Since the entire system for a time period is moving in the same direction, $\underline{v}(n)$ have an expected value different than zero.

(2) $\underline{u}(n)$, $\underline{v}(n)$ are not uncorrelated since both depend upon the power injections.

(3) The accuracy of the DC model does not suffice for this problem.

In reference (33) information from outages in the internal system are used to obtain the equivalent system. If $\underline{Z}^1$ and $\underline{Z}^2$ are pre and post outage internal system measurement vectors, then

$$\underline{Z}^1 = h^1(\underline{x}^1) + \underline{v}^1$$

$$\underline{Z}^2 = h^2(\underline{x}^2) + \underline{v}^2$$

where $\underline{x}^1$ and $\underline{x}^2$ are the pre and post outage state vectors, $\underline{v}^1$ and $\underline{v}^2$ are measurement error vectors with zero mean and covariances R_1, R_2. It is assumed that the boundary buses have been classified as load or as generation buses. For contingency analysis, the real power and voltage magnitudes at generation buses and the real and reactive powers at load buses are assumed to be constant. All these quantities define the vector $\underline{C}$. If $\underline{C}^1$ and $\underline{C}^2$ denote the pre and post outage cases, then

$$\underline{C}^1 = \underline{C}^2 + \underline{v}^3 \tag{37}$$

where $\underline{v}^3$ is a random vector of zero mean and covariance R_3, and

$$\underline{C}^1 = F^1(\underline{x}^1,\underline{p}) \tag{38}$$

$$\underline{C}^2 = F^2(\underline{x}^2,\underline{p}) \tag{39}$$

$\underline{p}$ is the vector of external network equivalent parameters, with initial value $\underline{p}^0$ and a priori covariance error matrix M_0.

Equations (37), (38), and (39) are combined to give:

$$\underline{F}^3 = 0 = F^2(\underline{x}^2,p) - F^2(\underline{x}^1,p) + \underline{v}^3 \underline{\Delta}\; g(\underline{x}^1,\underline{x}^2,p) + \underline{v}^3 \tag{40}$$

The optimum $\hat{\underline{x}}^1$, $\hat{\underline{x}}^2$, and $\hat{p}$ are those which minimize the index:

$$J = (\underline{p}-\underline{p}^0)^T M_0^{-1}(\underline{p}-\underline{p}^0) + (\underline{Z}^1-h^1(\underline{x}^1))^T R^{-1}(\underline{Z}^1-h^1(\underline{x}^1))$$

$$+ (\underline{Z}^2-h^2(\underline{x}^2))^T R_2^{-1}(\underline{Z}^2-h^2(\underline{x}^2))$$

$$+ (\underline{Z}^3-g(\underline{x}^1,\underline{x}^2,\underline{p}))^T R_3^{-1}(\underline{Z}^3-g(\underline{x}^1,\underline{x}^2,\underline{p}). \tag{41}$$

3. PROBLEM DESCRIPTION

3.1 Introduction

Given a power system which is observable to a state estimator and an external system connected, find an equivalent representation of the external system which will satisfy the following objectives:

(1) It is accurate, in the sense, that it should reproduce the true power flows and voltage levels for contingency analysis.

(2) It accounts for unreported changes in the external system.

The second objective needs some clarification. Two kinds of unreported changes may occur:

(a) Transmission line outages

(b) Generator outages

To account for these changes means either the equivalent is insensitive to these changes or it is sensitive, in which case, they should be detected and the equivalent must be modified.

In our investigation, we sought to optimize the equivalent representation of the external system for the following cases:

(a) The topology and the parameter values of the external network are well defined.

(b) No information about the external system is known.

The general problem will be investigated by examining four simpler subproblems.

Subproblem 1

Given: Complete information for the internal system. Topology and parameter values of the external system.

Find: Equivalent representation such that contingency analysis will be accurate.

Subproblem 2

Given: Complete information for the internal system. Topology and parameter values of the external system.

Find: Equivalent representation such that:

(a) Contingency analysis will be accurate.

(b) To account for unreported changes in the external system.

Suproblem 3

Given: Complete information for the internal system.

Find: Equivalent representation such that contingency analysis will be accurate.

Subproblem 4

Given: Complete information for the internal system.

Find: Equivalent representation such that:

(a) Contingency analysis will be accurate.

(b) To account for unreported changes in the external system.

The subproblems will be stated in terms of the following accuracy and sensitivity indices.

3.2 Accuracy Indices

The boundary buses are considered to be load buses throughout this investigation. The above assumption has an impact on the accuracy of the equivalent representation of the external system. Loosely speaking, accuracy means the ability of the equivalent system to reproduce the true power flows and voltage levels of the internal system for a series of postulated outages in the internal system. The above defined accuracy can be measured with accuracy indices. The accuracy indices should reflect the confidence we have on the assumption that the boundary buses behave as load buses.

Let N denote the number of postulated outages in the internal system and let b denote the number of the boundary buses.

Define

$$S \triangleq \frac{1}{2Nb} \sum_{k=1}^{N} \sum_{j=1}^{b} \{(P_j^{1k}-P_j^{2k})^2 + (Q_j^{1k}-Q_j^{2k})^2\} \tag{42}$$

where:

P_j^{1k}, P_j^{2k} $\triangleq$ real injected power at the j^{th} bus before and after the k^{th} outage

Q_j^{1k}, Q_j^{2k} $\triangleq$ reactive injected power at the j^{th} bus before and after the k^{th} outage

Define:

$$MP \triangleq \sum \max_{\substack{k=1,\ldots,N \\ j=1,\ldots,b}} |P_j^{1k} - P_j^{2k}|$$

$$MQ \triangleq \sum \max_{\substack{k=1,\ldots,N \\ j=1,\ldots,b}} |Q_j^{1k} - Q_j^{2k}|$$

An equivalent representation is accurate if

$$S < \overline{S}$$

and

$$MP < \overline{MP} \qquad (44)$$
$$MQ < \overline{MQ}$$

The values of $\overline{S}$, $\overline{MP}$, $\overline{MW}$ should be predetermined by engineering judgement, according to the requirements and applications of the equivalence techniques. Definitely one needs more accuracy for on-line operation than for planning purposes.

3.3 Sensitivity Indices

These indices should reflect how much the accuracy indices S, MP, MQ change when unreported changes take place in the external system.

We denote, by Δ, the set of changes (line outages, generator outages) in the external system for which we are primarily interested.

If for a change $j\epsilon\Delta$ the accuracy indices become $(S)_j$, $(MP)_j$, and $(MQ)_j$, we say that the equivalent representation is insensitive to this change if:

$$\frac{(S)_j}{S} - 1 < C_1$$

$$\frac{(MP)_j}{MP} - 1 < C_2$$

$$\frac{(MQ)_j}{MQ} - 1 < C_3 \qquad (46)$$

C_1, C_2, and C_3 are positive constants which will be predetermined by engineering judgement.

Following, we present the four subproblems we defined earlier. For each subproblem the equivalent model will be presented and the associate tests.

Subproblem 1

The Norton-type equivalent model is used. The relevant theory was presented earlier. To compute the Norton-equivalent, sparsity techniques, and gaussian elimination will be applied. The model should be tested for accuracy for a set of outages in the internal system. If the tests are successful, the equivalent model is satisfactory. If not, the proposed method for subproblem 3 should be applied.

Norton-type equivalents present a problem associated with the sparsity of the equivalent model. If the number of boundary buses b is large, i.e the internal system is highly interconnected to the external system, the sparsity of the equivalent model is destroyed; the Norton equivalent will give

$$\frac{b(b-1)}{2}$$

equivalent branches between the boundary buses and therefore the admittance matrix of the internal system will not be any longer sparse. Some compromise between desirable accuracy and sparsity is necessary. We propose a very simple scheme.

For each branch j of these $\frac{b(b-1)}{2}$ equivalent branches, compute

$$(\Gamma P)_j = \frac{1}{N} \sum_{k=1}^{N} |P_j^{2k}| \qquad (47)$$

$$(\Gamma Q)_j = \frac{1}{N} \sum_{k=1}^{N} |Q_j^{2k}|$$

where P_j^{2k}, Q_j^{2k} are the real and reactive flows in the j^{th} branch after the k^{th} outage.

Reject all branches which have been generated by the equivalent and which satisfy the following inequalities:

$$(\Gamma P)_j < \overline{\Gamma P}$$

$$(\Gamma Q)_j < \overline{\Gamma Q}$$

The threshold values $\overline{\Gamma P}$ and $\overline{\Gamma Q}$ will determine the compromise between accuracy and sparsity.

Subproblem 2

We use, again, as equivalent model the Norton-type equivalent. The model should first be tested for accuracy for a given set of postulated outages in the internal system.

Next the sensitivity of this model to changes in the external system is examined. For these outages which the model is sensitive, a detection scheme needs to be developed.

We propose a detection scheme based upon the assumption that the decoupled model between (MV-θ) and (MVAR-V) is valid. The motive for this assumption is that we are interested in detection and not accuracy.

We assume also that:

(1) The susceptances of the transmission lines are much higher than the conductances, i.e.

$$G_{ij} = 0$$

(2) Voltage magnitudes are constant and equal to 1 p.u., i.e.

$$v_i = 1 \text{ p.u.}$$

(3) The voltage phase angle difference across a line is small, i.e.

$$\sin(\theta_i - \theta_j) \approx \theta_i - \theta_j$$

One can write then for the entire area

$$\underline{P} = A\underline{\theta} \tag{48}$$

where $\underline{P}$ is the vector of real injections and $\underline{\theta}$ is the vector of the voltage phase angles and

$$a_{ij} = \begin{cases} B_{ij} & \text{for } i \neq j \\ -\sum\limits_{\substack{j \neq i \\ j\ a(i)}} B_{ij} & \text{for } i = j \end{cases}$$

where a(i) is the set of buses connected to the i^{th} bus.

Equation (48) can be written as:

$$\begin{bmatrix} A_{EE} & A_{ER} \\ A_{RE} & A_{RR} \end{bmatrix} \begin{bmatrix} \underline{\theta}_E \\ \underline{\theta}_R \end{bmatrix} = \begin{bmatrix} \underline{P}_E \\ \underline{P}_R \end{bmatrix} \tag{49}$$

where the subscripts E and R refer to external and reduced system respectively. By eliminating $\underline{\theta}_E$ from (49), one obtains

$$A_{eq}\underline{\theta}_R = \underline{P}_{eq} \qquad (50)$$

where:

$$A_{eq} = A_{RR} - A_{RE}A_{EE}^{-1}A_{ER}$$

$$\underline{P}_{eq} = \underline{P}_R - A_{RE}A_{EE}^{-1}\underline{P}_E$$

Notice that changes in the external system affect not only the injections at the boundary buses but also the impedances of the equivalent branches between the boundary buses. The detection scheme is based on the following theorem.

Theorem: Following the outage of a transmission line which connects the i^{th} and j^{th} buses of the external system, the vector of the voltage phase angles of the reduced system changes by a vector $\underline{\Delta\theta}_R$ such that:

$$A_{eq}\,\underline{\Delta\theta}_R = \lambda\underline{C} \qquad (51)$$

where λ is a constant and $\underline{C}$ a vector which completely characterizes the line outage. The vector $\underline{C}$ is defined as:

$$\underline{C} = A_{RE}A_{EE}^{-1}\underline{e}_{ij} \qquad (52)$$

where:

$$e_{ij} = \begin{bmatrix} 0 \\ 1 \\ -1 \\ 0 \end{bmatrix} \begin{array}{l} \\ \leftarrow i^{th} \text{ entry} \\ \leftarrow j^{th} \text{ entry} \\ \\ \end{array} \qquad (53)$$

Proof: Following the outage of a transmission line which connects the i^{th} and j^{th} bus of the external system, the matrix A_{EE} is modified as:

$$A'_{EE} = A_{EE} + a\underline{e}_{ij}\underline{e}_{ij}^T \tag{54}$$

where:

$$a = B_{ij} \tag{55}$$

By applying the matrix inversion lemma, one obtains:

$$(A'_{EE})^{-1} = (A_{EE} + a\underline{e}_{ij}\underline{e}_{ij}^T)^{-1} = A_{EE}^{-1} - \frac{a}{D} A_{EE}^{-1}\underline{e}_{ij}\underline{e}_{ij}^T A_{EE}^{-1} \tag{56}$$

where:

$$D = 1 + a\underline{e}_{ij}^T A_{EE}^{-1}\underline{e}_{ij} \quad \text{(scalar)} \tag{57}$$

Let's define as

$$\underline{\beta} \triangleq A_{EE}^{-1}\underline{e}_{ij} \tag{58}$$

then

$$(A'_{EE})^{-1} = A_{EE}^{-1} - \frac{a}{D}\,\underline{\beta\beta}^T \tag{59}$$

The equivalent model after the outage becomes:

$$\begin{aligned} A'_{eq} &= A_{RR} - A_{RE}(A_{EE}^{-1} - \frac{a}{D}\,\underline{\beta\beta}^T)A_{ER} \\ &= A_{eq} + \frac{a}{D} A_{RE}\underline{\beta\beta}^T A_{ER} \\ &= A_{eq} + \frac{a}{D}\,\underline{C}\,\underline{C}^T \end{aligned} \tag{60}$$

where $\underline{C}$ was defined earlier.

The modified vector of the real injection is:

$$\underline{P}'_{eq} = \underline{P}_R - A_{RE}(A_{EE}^{-1} - \frac{a}{D} A_{EE}^{-1}\underline{e}_{ij}\underline{e}_{ij}^T A_{EE}^{-1})\underline{P}_E$$

$$= \underline{P}_R - A_{RE}A_{EE}^{-1}\underline{P}_E + \frac{a}{D} A_{RE}A_{EE}^{-1}\underline{e}_{ij}\underline{e}_{ij}^T A_{EE}^{-1}\underline{P}_E \tag{61}$$

If we define as $\mu = \underline{e}_{ij}^T A_{EE}^{-1}\underline{P}_E$ (scalar), then

$$\underline{P}'_{eq} = \underline{P}_{eq} + \frac{a\mu}{D}\underline{C} \tag{62}$$

If the voltage phase angles of the buses in the internal system, after the outage in the external system, change from $\underline{\theta}_R$ to

$$\underline{\theta}_R + \underline{\Delta\theta}_R$$

then

$$A'_{eq}(\underline{\theta}_R + \underline{\Delta\theta}_R) = \underline{P}'_{eq} \tag{63}$$

where:

$$A_{eq} \cdot \underline{\theta}_R = \underline{P}_{eq} \tag{64}$$

By substituting the expressions for A'_{eq} and P'_{eq}, one obtains:

$$(A_{eq} + \frac{a}{D}\underline{C}\,\underline{C}^T)(\underline{\theta}_R + \underline{\Delta\theta}_R) = \underline{P}_{eq} + \frac{a\mu}{D}\underline{C} \tag{65}$$

or

$$A_{eq}\underline{\theta}_R + A_{eq}\underline{\Delta\theta}_R + \frac{a}{D}\underline{C}\,\underline{C}^T(\underline{\theta}_R + \underline{\Delta\theta}_R) = \underline{P}_{eq} + \frac{a\mu}{D}\underline{C} \tag{65'}$$

Since

$$A_{eq}\underline{\theta}_R = \underline{P}_{eq}$$

and

$$\underline{C}^T(\underline{\theta}_R + \underline{\Delta\theta}_R)$$

is scalar. The above expression can be written as:

$$A_{eq}\underline{\Delta\theta}_R = \frac{a}{D}\{\mu - \underline{C}^T(\underline{\theta}_R + \underline{\Delta\theta}_R)\}\underline{C} \tag{66}$$

or as:

$$A_{eq}\underline{\Delta\theta}_R = \lambda\underline{C} \tag{67}$$

where:

$$\lambda = \frac{a}{D}\{\mu - \underline{C}^T(\underline{\theta}_R + \underline{\Delta\theta}_R)\} \text{ Q.E.D.} \tag{68}$$

Since the study area is observable to a state estimator, the vectors $\underline{\theta}_R$ and $\underline{\theta}_R + \underline{\Delta\theta}_R$, i.e. the voltage phase angles of the buses of the study area before and after the outage in the external system are known. The vector

$$\underline{y} \triangleq A_{eq} \cdot \underline{\Delta\theta}_R \tag{69}$$

is also a known vector.

If NOUT is the number of the lines of the external system for which we are interested, then for each one there is a vector

$$\underline{C}_i \quad i = 1, \ldots, \text{NOUT}$$

and a corresponding normalized vector $\underline{C}_{i,N}$.

When the estimator detects a sudden change in the voltage phase angles, the vector $\underline{y}$ and the corresponding normalized vector $\underline{y}_N$ are calculated.

For each vector $\underline{C}_{i,N}$, the inner product

$$\underline{y}_N \cdot \underline{C}_{i,N}$$

is computed. The line outage gives the maximum inner product.

Subproblem 3

We propose to obtain the equivalent model by using data from on-line environment scheduled switching operations together with on-line state estimation. The unknowns of the model are the conductances and susceptances of the equivalent branches between the boundary buses and optional shunt susceptances at the boundary buses.

Let $\underline{u}$ denote the vector of all unknown network equivalent parameters and $\underline{x}$ denote the vector of boundary complex bus voltages. Assume that prior to an outage k (k=1, . . . ,N) $\underline{x}$ is known and given by $\underline{x}^{1k}$. Also assume that following that outage, $\underline{x}$ is also known and given by $\underline{x}^{2k}$. The vectors of real and reactive injections at the boundary buses before and after the k^{th} outage are given by:

$$\underline{I}^{1k} = A(\underline{x}^{1k})\underline{u} + \underline{T}^{1k}$$

$$\underline{I}^{2k} = A(\underline{x}^{2k})\underline{u} + \underline{T}^{2k} \tag{70}$$

where:

$\underline{I}^{1k}$, $\underline{I}^{2k}$ $\triangleq$ vectors of pre and post-outage injected powers at all boundary buses

$\underline{T}^{1k}$, T^{2k} $\triangleq$ vectors of pre and post-outage power flows from the boundary buses to the internal system. These are known quantities.

$A(\underline{x}^{1k}), A(\underline{x}^{2k})$ $\triangleq$ matrices which are strictly dependent on $\underline{x}^{1k}$ and $\underline{x}^{2k}$ (and possibly internal system admittances).

Note that the injections $\underline{I}$ are linear in $\underline{u}$. The problem is: Find $\underline{u}$ such that the vectors of real and reactive injections remain constant before and after the outages, i.e. the boundary buses behave as load buses.

One can write

$$\begin{aligned} \underline{C}^k &= \underline{I}^{1k} - \underline{I}^{2k} \\ &= [A(\underline{x}^{1k}) - A(\underline{x}^{2k})]\underline{u} + \underline{T}^{1k} - \underline{T}^{2k} \\ &= F^k\underline{u} + \underline{M}^k \end{aligned} \tag{71}$$

The vector $\underline{u}$ is computed by minimizing the quadratic performance index:

$$J = \sum_{k=1}^{N} (\underline{C}^k)^T \underline{C}^k \tag{72}$$

The optimality condition $\frac{\partial J}{\partial \underline{u}} = \underline{0}$ yields:

$$\frac{\partial J}{\partial \underline{u}} = \underline{0} = 2\{\sum_{k=1}^{N} (F^k)^T (F^k\underline{u} + \underline{M}^k)\} \tag{73}$$

and the optimal solution will be:

$$\hat{\underline{u}} = -[\sum_{k=1}^{N} (F^k)^T F^k]^{-1} [\sum_{k=1}^{N} (F^k)^T \underline{M}^k \tag{74}$$

with this value for $\underline{u}$, the performance index becomes:

$$\hat{J} = \sum_{k=1}^{N} (\underline{M}^k)^T \underline{M}^k - [\sum_{k=1}^{N} (F^k)^T \underline{M}^k]^T (\sum_{k=1}^{N} (F^k)^T F^k)^{-1} (\sum_{k=1}^{N} (F^k)^T \underline{M}^k) \tag{75}$$

Note that $\hat{J}$ = 2NbS, where S is the index for accuracy defined earlier.

This model should be tested for accuracy for the given set of N outages. If the tests are successful, this model is satisfactory. If not, we propose to find the equivalent model by solving the following problem.

Find $\underline{u}$ such that the performance index is minimized

$$J = \sum_{k=1}^{N} (\underline{C}^k)^T \underline{C}^k$$

subject to

$$|C_i^k| \leq \overline{C}_i \tag{76}$$

for all i, k=1, . . . ,N.

The solution of the above problem will be satisfactory if the performance index J, evaluated at the optimum, satisfies the following constraint:

$$\hat{J} \leq 2Nb\overline{S}$$

Subproblem 4

We propose to use as equivalent model the models we derived for subproblem 3. The sensitivity of the model to changes in the external system should be examined. The detection scheme applicable for Norton equivalents, is not applicable in this case.

Assume that data from M switching operations in the internal system while changes in the external system took place are available. This information can be incorporated with similar ideas we used to obtain the equivalent representation earlier.

Find $\underline{u}$ such that:

$$J = \sum_{k=1}^{N+M} (\underline{C}^k)^T \underline{C}^k \tag{77}$$

For this model, evaluate the indices for accuracy and sensitivity. If these indices are satisfactory, the model is an acceptable one. If not, find $\underline{u}$ such that

$$J = \sum_{k=1}^{N+M} (\underline{C}^k)^T \underline{C}^k$$

is minimum and subject to

$$|C_i^k| \leq \overline{C}_i \tag{78}$$

for all i, k=1, . . . ,N+M.

This model does not guarantee insensitivity to all unreported changes in the external system. However, it is the best model for the available information.

3.4 Discussion

In the beginning of this section, the general form of the equivalent problem has been stated. The possible types of information available to find the equivalent model and the types of constraints the equivalent model should satisfy are defined. The size of the problem is huge and direct solution would present implementation difficulties. Instead of solving the general problem directly, four subproblems were introduced and solution to these subproblems were proposed.

Mathematically speaking, the problem is an optimization one.

Find a vector $\underline{u}$ subject to equality constraints (load flow equations before and after a set of outages)

$$\underline{g}(\underline{u}) = \underline{0} \tag{79}$$

and subject to inequality constraints

$$\underline{F}_1(\underline{u}) \leq \underline{0} \quad \text{(accuracy)} \tag{80}$$

$$\underline{F}_2(\underline{u}) \leq \underline{0} \quad \text{(sensitivity)} \tag{81}$$

As criterion of satisfying the equality constraints, the performance index

$$J = \underline{g}^T \underline{g} \tag{82}$$

is selected. The statement of the problem is:

$$\min_{\underline{u}} J = \underline{g}^T(\underline{u})\underline{g}(\underline{u}) \tag{83}$$

subject to

$$\underline{F}_1(\underline{u}) \leq \underline{0} \tag{84}$$

$$\underline{F}_2(\underline{u}) \leq \underline{0} \tag{85}$$

In subproblems 1 and 2, the vector $\underline{u}$ is computed using network reduction (Norton equivalent) assuming that the topology and parameter values of the external system are known. If the performance index is satisfactory (less than $\bar{J}$) and the inequalities are satisfied, the Norton-type equivalent model is an acceptable one.

If the inequalities concerning the sensitivity of the model to unreported external changes are violated, a detection scheme (subproblem 2) is proposed to alleviate this problem. If the external system is not known, or the performance index by using the Norton equivalent is not satisfactory, or constraints involving the accuracy of the model are violated, an equivalent model is proposed in subproblem 3 to minimize the performance index J. This model is then checked if it satisfies the inequality constraints. If the accuracy constraints are violated, the solution of the following problem is proposed.

$$\min_{\underline{u}} J = \underline{g}^T(\underline{u})\underline{g}(\underline{u}) \tag{86}$$

subject to:

$$\underline{F}_1 (\underline{u}) \leq \underline{0} \tag{87}$$

The inequalities $\underline{F}_2(\underline{u}) \leq \underline{0}$ are then checked. If these inequalities are violated, the problem is augmented with the constraints $\underline{F}_2(\underline{u}) \leq \underline{0}$ as it has been stated in subproblem 4.

The problem and its flow chart are summarized in Figure 11.

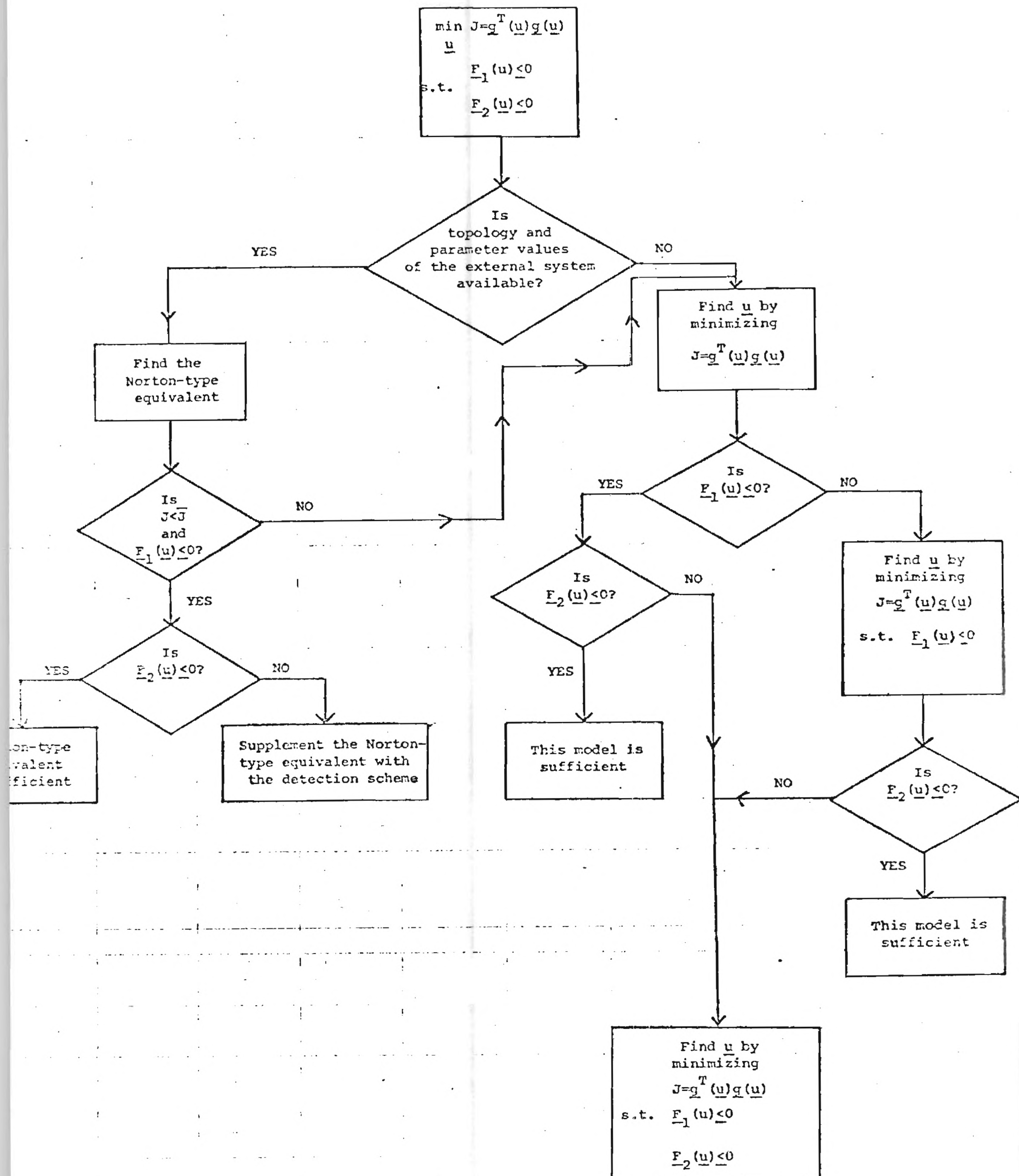


FIGURE 11. Flow Chart Summarizing all Possible Alternatives for Equivalencing in an On-Line Environment

4. TEST RESULTS

The following parts of our research have already been completed.

(1) A routine has been developed to compute the Norton-type equivalent when the topology and the parameter values of the external system are known. Gaussian elimination is the basis for the routine. To save computer space, sparsity techniques have been applied.

(2) A routine has been developed to compute the equivalent model by using information from the internal system only. The equivalent model is computed by minimizing the performance index

$$J = \sum_{k=1}^{N} (\underline{C}^k)^T \underline{C}^k \tag{88}$$

where:

$$\underline{C}^k = F^k \underline{u} + \underline{M}^k \tag{89}$$

The solution is given by:

$$\hat{\underline{u}} = -[\sum_{k=1}^{N} (F^k)^T F^k]^{-1} [\sum_{k=1}^{N} (F^k)^T \underline{M}^k] \tag{90}$$

(3) Both routines above have been applied to a 30 bus system as the entire area. Two cases were examined.

CASE 1

The internal system consisted of eight buses from which three were boundary buses as is shown in Figure 12. Five outages were considered in the internal system. Results are shown in Table V. We found that shunt terms at the boundary buses improve the accuracy of the equivalent model.

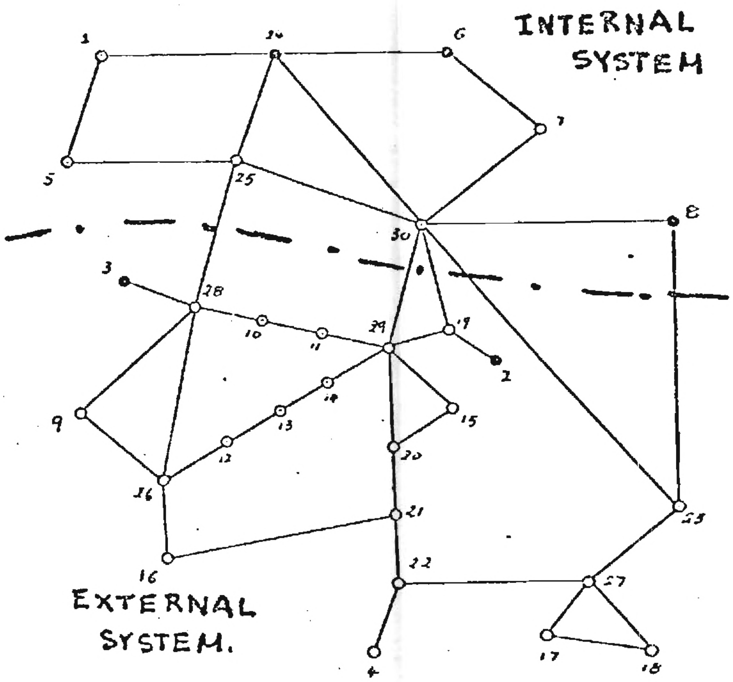


FIGURE 12. IEEE 30-Bus Test System Used in Simulation Analysis of Case 1.

TABLE V

Test Results for Case No. 1

	Norton Equivalent	Least Squares Optimization No Shunt Terms	Least Squares Optimization Includes Shunt Terms
G(8-25)	.02380	.17797	.29743
G(8-30)	7.36687	3.52793	- .09731
G(25-30)	6.65502	4.77236	4.64301
B(8-25)	- .06060	.45051	- .13431
B(8-30)	-25.49960	-12.49867	.07769
B(25-30)	-23.77281	-24.13382	-23.75592
BSHUNT(25)	.0	.0	- .80172
BSHUNT(30)	.0	.0	-13.62277
$S(MVA)^2$	12.76	6.75	.35

CASE 2

The internal system consisted of ten buses from which four were boundary buses as is shown in Figure 13. Nine outages were considered in the internal system. Results are shown in Table VI.

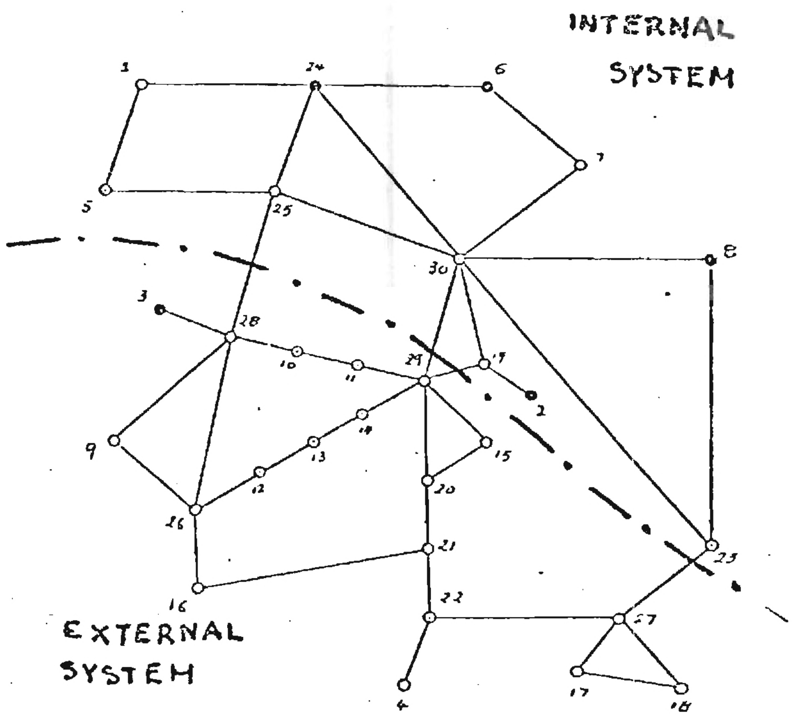


FIGURE 13. Case 2 Test System.

TABLE VI

Test Results for Case No. 2

	Norton Equivalent	Least Squares Optimization
G(19-23)	.16227	.11661
G(19-25)	.22402	.09799
G(19-30)	- .06380	.18188
G(23-25)	.06406	.29518
G(23-30)	4.39494	4.46412
G(25-30)	6.45774	5.89974
B(19-23)	- .47219	- .32902
B(19-25)	- 1.27638	- 1.28983
B(19-30)	- 6.02039	- 6.22274
B(23-25)	- .20294	- .29537
B(23-30)	-15.55699	-15.65216
B(25-30)	-22.56372	-22.28394
BSHUNT(19)	.0	- .50887
BSHUNT(23)	.0	- .33407
BSHUNT(25)	.0	- .13707
BSHUNT(30)	.0	.01755
$S(MVA)^2$	1.41	1.077

(4) Both routines have been applied to a 444 bus system as the entire area. The internal system consisted of 87 busses from which 31 were boundary busses. For different sets of outages, the equivalent model, based on least squares optimization, was calculated. For each model the accuracy indices S, MP, and MQ were evaluated and were compared to the corresponding accuracy indices given by the Norton equivalent. Three examples are shown below.

EXAMPLE 1: 29 outages were considered in the internal system

	Norton Equivalent	Least Squares Minimization
$S(MVA)^2$	339.48	94.36
MP (MW)	111.54	48.33
MQ (MVAR)	279.78	107.47

EXAMPLE 2: 19 outages were considered in the internal system

	Norton Equivalent	Least Squares Minimization
$S(MVA)^2$	418.94	83.42
MP (MW)	111.54	42.94
MQ (MVAR)	279.78	87.28

EXAMPLE 3 18 outages were considered in the internal system

	Norton Equivalent	Least Squares Optimization
$S (MVA)^2$	341.75	60.09
MP (MW)	111.54	22.01
MQ (MVAR)	196.94	57.47

We found that for some outages the Norton-equivalent gave completely erroneous results.

(5) A scheme to detect outages of transmission lines in the external system has been developed theoretically (page 21).

5. CONCLUSIONS

In this section we presented the state of the art in the area of equivalence in power systems.

Methods where buses from the external system are included jeopardize the accuracy of the equivalent representation since the status of the buses in the external system is unknown.

Methods where the Norton equivalent is applied to the boundary buses do not guarantee the accuracy of the model over all the set of postulated outages. The reason is that non linear events are studied using a model obtained by linear reduction of the external system.

The other drawback of the Norton-type equivalents is that they require complete knowledge of the external system but this information is not always available. Even if the topology and the parameter values of the external system are known, unreported changes in the external system affect the values of the impedances of the equivalent branches between the boundary buses. This is not taking into consideration by the existing methods.

The proposed research covers the general case where the topology and the parameter values of the external system may or may not be available. In the first case, the Norton equivalent is applied to the boundary buses and is tested for accuracy and sensitivity to unreported changes in the external system. If the model is accurate, a detection scheme is proposed to enable the operator to detect these outages and modify the equivalent model accordingly. If the Norton equivalent is not accurate or no information for the external system is available, a model is proposed based on least square optimization using information from the internal system only.

In summary, the determination of the equivalent representation of an external system is basically an optimization problem. However, in many cases all the required information is not available. The proposed research will find the best equivalent representation for the available information.

APPENDIX A

SENSITIVITY RELATIONS

Definitions:

$T_{ij} \triangleq$ Real power flow from node i to node j

$U_{ij} \triangleq$ Reactive power flow from node i to node j

$G_{ij} + j\, B_{ij} \triangleq$ Series admittance of branch i-j

$BSH_i \triangleq$ Shunt admittance of branch i-j referred to node i

$a_i \triangleq$ Tap setting in p.u. of the fixed-end tap of a transformer

$E_i + j\, F_j \triangleq$ Complex voltage at node i.

$$\frac{\partial T_{ij}}{\partial B_{ij}} = E_i F_j - E_j F_i$$

$$\frac{\partial T_{ij}}{\partial G_{ij}} = E_i^2 + F_i^2 - E_i E_j - F_i F_j$$

$$\frac{\partial U_{ij}}{\partial B_{ij}} = E_i^2 - F_i^2 + E_i E_j + F_i F_j$$

$$\frac{\partial U_{ij}}{\partial G_{ij}} = E_i F_j - E_j F_i$$

$$\frac{\partial U_{ij}}{\partial BSH_i} = -E_i^2 - F_i^2$$

$$\frac{\partial T_{ij}}{\partial a_i} = +\frac{1}{a_i}\left((2(E_i^2 + F_i^2) - (E_i E_j + F_i F_j))G_{ij} + (E_i F_j - E_j F_i)B_{ij}\right)$$

$$\frac{\partial U_{ij}}{\partial a_i} = \frac{1}{a_i}\left(B_{ij}(2(E_i^2 + F_i^2) - E_i E_j - F_i F_j) + 2BSH_i(E_i^2 + F_i^2) + G_{ij}(F_i E_j - F_j E_i)\right)$$

$$\frac{\partial T_{ij}}{\partial a_j} = \frac{1}{a_j}\left(G_{ij}(E_i E_j + F_i F_j) + B_{ij}(F_i E_j - F_j E_i)\right)$$

$$\frac{\partial U_{ij}}{\partial a_j} = \frac{1}{a_j} (G_{ij}(F_i E_j - F_j E_i) - B_{ij}(E_i E_j + F_i F_j))$$

REFERENCES

1. A. S. Debs and W. H. Litzenberger, "The BPA State Estimator Project: Tuning of the Network Model," paper presented at Summer Power Meeting, San Francisco, CA, July, 1975.

2. A. S. Debs and W. H. Litzenberger, "Implementation of the BPA On-Line State Estimator," paper presented at Power System Computation Conference, held in Cambridge, England in September 1975.

3. A. S. Debs, R. E. Larson, and L. P. Hajdu, "On-Line Sequential State Estimation for Power Systems," Proceedings of 1972 Power System Computation Conference held in Grenoble, France.

4. A. S. Debs, "Estimation of Steady-State Power System Model Parameters," IEEE Transactions on Power Apparatus and Systems, vol. PAS-93, No. 5, Sept./Oct. (1974).

5. K. A. Clements and R. J. Ringlee, "Treatment of Parameter Uncertainty in Power System State Estimation," Paper C-74-311-7 presented at Summer Power Meeting held in Anaheim, CA, July 1974.

6. A. S. Debs, "Estimation of Model Parameters for Power System Monitoring and Control," proposal submitted to National Science Foundation (Engineering Division), and resulted in Grant GK-37474, December 1972.

7. F. C. Schweppe--Discussion of Paper in Ref. 1 above.

8. N. Sato and W. F. Tinney, "Techniques for Exploiting the Sparsity of the Network Admittance Matrix, IEEE Trans. on Power Apparatus and Systems, vol. 82, December 1963.

9. Richard Bauman, et. al., "The Main Factors of Influence in the Mathematical Modeling of Actual Conditions in Power Systems," ETZ-A vol. 87, no. 32, Nov. 1966, pp. 818-823, Translated into English by approval of Bonneville Power Administration c/o H. W. Dommel.

10. A. S. Debs, "Power System Model Inaccuracies and Sequential Tracking Estimation," Technical Memorandum PAU 949-3-1 prepared for Bonneville Power Administration by Systems Control, Inc., Contract 14-03-79968, Exhibit F, October 1971.

11. T. Stuart and C. J. Herget, "Sensitivity Analysis of Weighted Least Squares State Estimation for Power Systems," IEEE Trans. on Power Apparatus and Systems, vol. PAS-92, No. 5, Sept./Oct. 1973.

12. K. A. Clements, et. al., "The Effects of Measurement Non-Simultansity, Bias, and Parameter Uncertainty on Power System State Estimation," 1973 PICA Conference Proceedings, June 1973.

13. A. S. Debs, "Data Base for Real-Time Power System Control," invited paper to Allerton Conference on Circuits and Systems held in Montecello, Illinois (October 1973).

14. H. D. Merrill and F. C. Schweppe, "On-line system model error correction," IEEE Winter Power Meeting 1973, C73-106-2.

15. E. Hanschin, Editor, "Real-Time Control of Electric Power Systems," Elsivice Publishing Co., New York, 1973.

16. N. M. Peterson, W. F. Tinney, and D. W. Bree, "Iterative Linear AC Power Flow Solutions for Fast Approximate Outage Studies," IEEE Trans. PAS-91, no. 5, Sept./Oct. 1972.

17. R. A. Pyne, "Bus Load Forecasting and Its Intended Use in System Security Analysis," 1974 Proceedings of IEEE Conference on Decision and Control held in Phoenix, Arizona, November 1974.

18. G. Contaxis and A. S. Debs, "Network Equivalents for On-Line Power System Security Assessment," presented at IEEE Southeast Conf., held in Clemson, SC, April 1976.

19. J. F. Dopazo, et. al., "An External System Equivalent Model Using Real-Time Measurements for System Security Evaluation," paper F76370-7 presented at IEEE Summer Power Meeting, Portland, Oregon, July 1976.

20. J. B. Ward, "Equivalent Circuits for Power-Flow Studies," AIEE Trans., vol. 68, pp. 373-382, 1949.

21. A. S. Debs, A. R. Benson, "Security Assessment of Power Systems," Final Report to Energy Research and Development Administration prepared under contract to Georgia Institute of Technology, (July 1975).

22. J. C. Kaltenbach, L. P. Hajdu, "Optimal Corrective Rescheduling for Power System Security," IEEE Trans. Power App. Syst., Vol. PAS-90, pp. 843-851, March/April 1971.

23. T. E. DyLiacco, B. F. Wirtz, D. A. Wheeler, "Automation of the CEI System for Security," IEEE Trans. Power App. Syst., vol. PAS-91, pp. 831-843, May/June 1972.

24. N. M. Peterson, W. F. Tinney, D. W. Bree, Jr., "Iterative Linear AC Power Flow Solution for Fast Approximate Outage Studies," IEEE Trans. Power App. Syst., vol. PAS-91, pp. 2048-2056, Sept./Oct. 1972.

25. M. S. Sachdev and S. A. Ibrahim, "A Fast Approximate Technique for Outage Studies in Power System Planning and Operation," presented at IEEE PES Summer Meeting, Vancouver, July 15-20, 1973.

26. B. Stott, O. Alsac, "Fast Decoupled Load Flow," IEEE Trans. Power App. Syst., vol. PAS-93, pp. 859-869, May/June 1974.

27. H. Duran, N. Arvanitidis, "Simplifications for Area Security Analysis: A new look at equivalence," IEEE Trans. Power App. Syst., vol. PAS-91, pp. 670-679, March/April 1972.

28. W. F. Tinney, W. L. Powell, N. M. Peterson, "Sparsity-Oriented Network Reduction," 8th PICA Conference Proceedings, June 1973.

29. D. Denzel, R. Graf, J. Verstege, "Practical Use of Equivalents for Unobservable Networks in On-Line Security Monitoring," Power Systems Computation Conference Proceedings, Cambridge, Sept. 1975.

30. IBM Research Division, "Application of Security Indices and Restraints to a Real Power System," for the Electric Power Research Institute (February 1974).

31. E. K. Paulsson, "Network Equivalents for On-Line Systems," paper presented at IEEE Summer Power Meeting, July 1974.

32. F. C. Schweppe, "Role of System Identification in Electric Power Systems," Power Systems Computation Conference Proceedings, Grenoble, France, Sept. 1972.

33. A. S. Debs, "Estimation of External Network Equivalents from Internal System Data," IEEE Trans. Power App. Syst., vol. PAS-93, no. 2, pp. 273-279, March/April 1975.

34. W. F. Tinney, J. W. Walker, "Direct Solutions of Sparse Network Equations by Optimally Ordered Triangular Factorization," Proc. IEEE, vol. 55, pp. 1801-1809, Nov. 1967.

35. W. D. Stevenson, Jr., Elements of Power System Analysis, New York: McGraw-Hill, 1962.

36. H. A. Taha, Operations Research: An Introduction, New York: MacMillan Publishing Co., 1971.